THE SECOND CANADA-CHINA HEAVY OIL TECHNOLOGY SYMPOSIUM

ORGANIZED AND SPONSORED BY

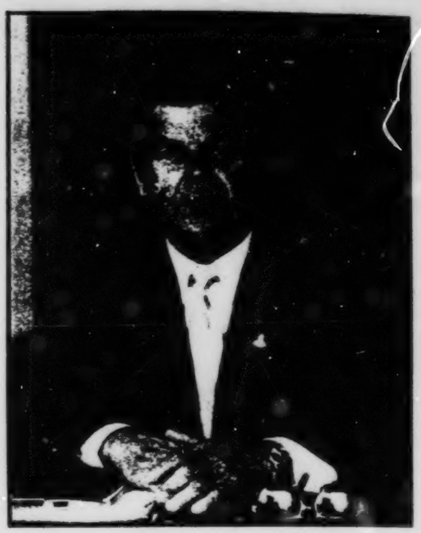
ALBERTA OIL SANDS TECHNOLOGY AND RESEARCH AUTHORITY

AND

CHINA NATIONAL PETROLEUM CORPORATION

OCTOBER 29, 1990 – NOVEMBER 1, 1990 • CHINA

A Message from the Chairman of AOSTRA



Dear Friends:

I take great pleasure in welcoming you to the Second China-Canada Heavy Oil Symposium. I have every confidence that the sharing of knowledge and interest at this meeting will further result in a great future for oil sands and heavy oil development for our two great nations. I wish to compliment my colleagues from the China National Petroleum Corporation (CNPC) on their foresight and express my appreciation for their invitation to make this a joint conference with the Alberta Oil Sands Technology and Research Authority (AOSTRA).

In 1987, AOSTRA joined the Research Institute of Petroleum Exploration and Development (RIPED) in organizing the first ever China-Canada Heavy Oil Technology Symposium at Zhuo Zhou City. It was a very successful conference which led to several trade opportunities in the petroleum industry between our two countries. Furthermore, because of mutual interest in and understanding of heavy oil technology, the 1987 Symposium also resulted in CNPC becoming a member of AOSTRA's two major sponsored research programs — the AOSTRA/ARC/Industry Access Program and AOSTRA/University/Industry Access Program. The success of the 1987 Symposium led us to believe that there was enough desire to hold this Second China-Canada Heavy Oil Symposium.

Over the past fifteen years, AOSTRA has become an organization unique in the world and has invested approximately one billion dollars. with its industrial partners, to develop oil sands, heavy oil and enhanced oil recovery technologies. During the past three years, we, at AOSTRA, have accomplished several breakthrough technologies. The Second Canada-China Heavy Oil Symposium is a perfect forum to share our knowledge and to discuss these new technologies, such as the Underground Test Facility (UTF) and its associated technologies from the Shaft and Tunnel Concept to the Steam Assisted Gravity Drainage Process; the AOSTRA-Taciuk Process (ATP) for Oilfield Waste Treatment; and the Anti-Water Coning Technology (AWACT).

The proceedings of the Symposium contain forty-one papers with Canada contributing twenty-four of these papers. The papers in this volume are divided into six sections: (1) General Session Overview; (2) Reservoir Access; (3) Well Completion; (4) Production Technology; (5) Recovery Technology; and (6) Surface Facilities. They represent the significant advances of science and technology in the past five years in the development of heavy oil technology.

AOSTRA, with the cooperation of the Alberta Department of Economic Development and Trade and the Canadian departments of Industry, Science and Technology, and External Affairs, considers this bilateral heavy oil symposium a major event of international cooperation between Canada and China, specifically during the 20th Anniversary of normalization of diplomatic relationships between Canada and the People's Republic of China. It will also be seen as an important milestone in technical cooperation between Alberta and China.

Many people have helped in many ways and it is a pleasure to thank them all. First, we express our gratitude to the Government of Alberta for its support and to the Government of Canada for providing assistance through the National Trade and Strategic Fund. We would like to thank the many individuals who have contributed to the planning and organization of the Symposium with a special thank you going to Dr. Chu Hsi for his indispensable service in every stage of planning and organizing the conference. We also would like to thank all the authors for their valuable contributions to the technical program of this symposium. Last but not least, all the support and assistance provided by CNPC is gratefully acknowledged.

WJ Yurko

W.J. Yurko
Chairman and
Chief Executive Officer

92-07596/

AGENDA

	MORNING	AFTERNOON
October 29, 1990	Opening Ceremony	General Session – Overview
October 30, 1990	Session I – Reservoir Access Session II – Well Completion	Session I – Reservoir Access Session II – Well Completion
October 31, 1990	Session III – Production Technology Session IV-1 – Recovery Technology	Session III – Production Technology Session IV-1 – Recovery Technology
November 1, 1990	Session IV-2 – Recovery Technology Session V – Surface Facilities	Session IV-2 – Recovery Technology Session V – Surface Facilities

Closing Ceremony 5:15 p.m.

October 29, 1990 • Opening Ceremony

Conference Co-Chairmen: **Mr. W.B. Tan (CNPC)**
Mr. W.J. Yurko (AOSTRA)

0900	Welcome	W.B. Tan
0915	Welcome	W.J. Yurko
0930	Opening Remarks	President, CNPC
0945	Opening Remarks	Ambassador of Canada
1000	Opening Remarks	M. Rasmuisson, Assistant Deputy Minister Alberta Economic Development and Trade
1020	Featured Speaker	M.A. Carrigy UNITAR/UNDP Information Centre for Heavy Crude and Tar Sands

OCTOBER 29, 1990 • GENERAL SESSION

OVERVIEW

Presiding: Mr. R.P. Wan (CNPC)
Dr. D.A. Redford (AOSTRA)

1300 – 1400	G-1	Current Trends in Heavy Oil and Tar Sands Research in Canada	D.A. Redford
1400 – 1500	G2	Review and Prospect of Heavy Oil Thermal Recovery Technology Research at the Research Institute of Petroleum Exploration and Development	W.Z. Liu
1500 – 1520		Coffee	
1520 – 1620	G-3	AOSTRA/ARC/Industry Joint Research in Advanced Thermal Recovery	C. Hsi/ P.R. Tremaine
1620 – 1720	G-4	AOSTRA/University Research	T.J. Cyr
1720 – 1820	G-5	Analysis of Results for Reservoir Description of a Heavy Oil Reservoir	Jixian Wang/ Chunzeng Lin

OCTOBER 30, 1990 • SESSION I

RESERVOIR ACCESS

Presiding: **Mr. Q.H. Wang (Liaohe Oilfield)**
Dr. R.M. Butler (University of Calgary)

0830 – 0930	I-1	Horizontal Drilling	Gerry Edwards
0930 – 1000		Coffee	
1000 – 1100	I-2	Horizontal Well Technology — An Assessment of Canadian Field Experience	R.G. Farquharson
1100 – 1200	I-3	Shaft and Tunnel Access Concept (SATAC)	H.G. Stephenson
1200 – 1330		Lunch	
1330 – 1430	I-4	The Scaled Physical Model Studies of Horizontal Fractures Assisted Steamflooding Super Heavy Oil	J.J. Lin/ W.Z. Liu/ J.P. Hu
1430 – 1530	I-5	How to Predict BHA Performance in Medium or Large-Curvature Horizontal Wells	Deli Gao/ Xisheng Liu
1530 – 1600		Coffee	
1600 – 1700	I-6	An Analysis of Development Effects of Steam Stimulation for Three Types of Heavy Oil Reservoir in Liaohe Oilfield	Weigeng Cao/ Ling Zhou

OCTOBER 30, 1990 • SESSION II

WELL COMPLETION

Presiding: Mr. K.X. Li (CNPC)
Mr. D.W.J. Courchene (ISTC)

0830 – 0930	II-1	Pre-Stress Completion	Zhunsheng Chai
0930 – 1000		Coffee	
1000 – 1100	II-2	Development of Novel Sand Exclusion Strategies for Vertical and Horizontal Wells Using Field and Laboratory Research	J.C. Suggett/ P. Toma/P. Harris/ G. Korpany/ B. King
1100 – 1200	II-3	Research of "One-Trip Tubing String" Gravel Pack Technique for Sand Control of Huff-and-Puff Wells	Duandong Chen/ Yigang Zhang
1200 – 1330		Lunch	
1330 – 1430	II-4	Slant Well Workovers (CANCELLED)	Rance Fisher
1430 – 1530	II-5	In Situ Monitoring Instrumentation at AOSTRA's Underground Test Facility	J.C. Suggett/ P.M. Collins/ A.W. Stokes
1530 – 1600		Coffee	
1600 – 1700	II-6	The Temperature and Pressure Measurement in Perforated Observation Wells and its Data Analysis and Evaluation	Zengshan Wang/ Shunlong Peng

OCTOBER 31, 1990 • SESSION III

PRODUCTION TECHNOLOGY

Presiding: Professor H.X. Wang (Petroleum University)
Dr. F.M. Mourits (CANMET)

0830 – 0930	III-1	Enhancement of Solids Removal from Horizontal Wells	P. Toma/P. Harris/ G. Korpany/ K. Non Chhom/ M. McCormack
0930 – 1000		Coffee	
1000 – 1100	III-2	A Study on Synthetical Relieving Plug Agent for Steam Huff-Puff Wells	Yunxin Cheng/ Biao Wang/ Zimian Hu/ Yinxue Jian
1100 – 1200	III-3	Pumping Technology of Directional Cluster Wells for Shallow Heavy Oil Reservoir	Dao Jun Zhu/ Zheng Jian Yin
1200 – 1330		Lunch	
1330 – 1430	III-4	Lifting Heavy Oil with Screw Pumps	Tim Presber
1430 – 1530	III-5	Viscous Crude Oil Production Technology for Steam Injection Wells	Jinguo Liang/ Minkang Wang/ Yin Ren/ Chen Shen/ Yongchang Fan Guangrong Hao
1530 – 1600		Coffee	
1600 – 1700	III-6	Sand-Filled Channels — A Novel Field Strategy for Enhancement of Thermal Recovery of Heavy Oil	P. Toma/ V. Reitman/ R. Coats/ G. Korpany/ D. Redford

OCTOBER 31, 1990 • SESSION IV-1

RECOVERY TECHNOLOGY

Presiding: Mr. W.Z. Liu (RIPED)
Dr. T.J. Cyr (AOSTRA)

0830 – 0930	IV-1	Steam Assisted Gravity Drainage — A General Review	R.M. Butler
0930 – 1000		Coffee	
1000 – 1100	IV-2	Numerical Simulation of Wellbore Effects on Steam-Assisted Gravity Drainage Process	Alan Siu/ Yau Kun Li/ Long Nghiem/ D.A. Redford
1100 – 1200	IV-3	Conformance Improvement by Using High Temperature Foams and Gels	E.E. Isaacs/ K. Green/ D. Maunder/ E. Jossy
1200 – 1330		Lunch	
1330 – 1430	IV-4	Study of Interfacial Tension and Emulsion Characteristics of Heavy Oil/Hot Caustic Solution Systems	Yueqiou Li/ Jianshe Wang/ Jingrong Zhang/ Tiande Shi
1430 – 1530	IV-5	In Situ Combustion in Canada	D. Bennion/ R.G. Moore
1530 – 1600		Coffee	
1600 – 1700	IV-6	Chemical Simulation of In Situ Combustion Process and the Associated Thermo-kinetic of Oxidation of Heavy Oil	Zhong L. Zhang/ Lai D. Shi/ Xie Q. Shen

NOVEMBER 1, 1990 • SESSION IV-2

RECOVERY TECHNOLOGY

Presiding: Mr. J.S. Wang (RIPED)
Dr. P. Toma (ARC)

0830 – 0930	IV-7	Laboratory and Field Study of Adding Petroleum Sulphonate to Cyclic Steam Wells	Shuangde Wang/ Wei Han
0930 – 1000		Coffee	
1000 – 1100	IV-8	Integrated Reservoir Analysis, A Case Study	J. Kramers/ S. Bachu/ D. Cuthiell/ L.P. Yuan
1100 – 1200	IV-9	The Property and Characteristics of Crude Oil in Shanjiashi Oilfield in the Process of Steam Soak	Jialing Jiang/ Xiaole Shi/ Huichun Fang
1200 – 1330		Lunch	
1330 – 1430	IV-10	Production Seismic	John Rees
1430 – 1530	IV-11	AWACT: Anti-Water Coning Technology	J.C. Suggett/ D.J. Stephenson/ R.W. Luhning/ M. Chmilar/ B. Anderson
1530 – 1600		Coffee	
1600 – 1700	IV-12	The Feasibility Study of Thermal Recovery for High Pour and Viscous Oil	Zhong He/ Wenzhang Liu/ Qi Jiang
1715		Closing Ceremony	

NOVEMBER 1, 1990 • SESSION V

SURFACE FACILITIES

Presiding: Mr. C.W. Miao (PPEI)
Dr. Chu Hsi (AOSTRA)

0830 – 0930	V-1	Satellite Facilities Design Considerations	R. Holcek/ I. Bradley/ T. Luu
0930 – 1000		Coffee	
1000 – 1100	V-2	AOSTRA Taciuk Processor: Technology for Oil Field Clean Up of Tank Bottoms and EOR Production Wastes	W. Taciuk/ D.P. Komery
1100 – 1200	V-3	Recent Advances in the Treatment of Produced Water from the In Situ Recovery of Heavy Oil	S.A. Zaidi/ S. Kok
1200 – 1330		Lunch	
1330 – 1430	V-4	Coal Fired Steam Generation for Heavy Oil Recovery	Keith Firmin
1430 – 1530	V-5	The Application of Reservoir Simulation as a Diagnosis Tool in the Development of a Thin and Extra-Viscous Oil Reservoir of Henan Oilfield	Zhenyu Song/ Jue Wang
1530 – 1600		Coffee	
1600 – 1700	V-6	Heavy Oil Production Improvement through Downhole Emulsification	F.M. Mourits
1715		Closing Ceremony	

SOME GLOBAL FACTORS INFLUENCING THE FUTURE OF HEAVY CRUDE AND TAR SANDS

by

Maurice A. Carrigy
Director

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OCTOBER 1990

SOME GLOBAL FACTORS INFLUENCING THE FUTURE OF HEAVY OIL CRUDE AND TAR SANDS

M.A. Carrigy

INTRODUCTION

There are many economic and technological factors that will influence the future development of heavy crude oil and tar sands but there are only two issues of global significance that are currently troubling long term policy decision makers on the future of this resource; they are the widespread belief that there will be ample supplies of cheap light crude oil, available to all, for the foreseeable future, and that continued burning of fossil fuels will jeopardize the survival of mankind by contributing to global warming and seal level changes.

Only the first concern will be addressed in this paper, however, it should be borne in mind that if the concern about global climate change becomes so compelling that international action must be taken to curb the burning of fossil fuel, the first concern becomes academic.

The following text is divided into four sections. Firstly, as background, the United Nations forecasts on conventional oil consumption to the year 2000 will be summarized. Secondly, the magnitude, quality and geographic distribution of the world's heavy oil and bitumen resources will be presented. Thirdly, the role of the UNITAR/UNDP Centre for Heavy Crude and Tar Sands in assisting with the dissemination of information and knowledge of the technology being used to develop these neglected resources will be discussed and finally, mention will be made of some of the environmental factors that might constrain their development.

BACKGROUND

In May, 1990 a report of the Secretary-General of the United Nations (A145/274), entitled *Energy Exploration and Development Trends in Developing Countries*, was presented to the General Assembly. The report predicts that the consumption of crude oil will increase from 55 million barrels per day in 1988 to 71 million barrels per day in 2000.

In the former centrally planned economies, Eastern Europe and the U.S.S.R., oil consumption rises from 9.0 million barrels per day in 1988 to 13 million barrels per day in 2000.

By contrast, oil consumption in developing countries is expected to increase from 14 million barrels per day in 1988 to 22 million barrels per day in 2000.

In many of the developing countries the traditional source of energy is non-commercial, consisting of fuel wood, charcoal, and agricultural waste, mainly straw and dung. Oil, however, is the preferred commercial energy source and supplies from 60 to 100 percent of the total commercial energy in many developing countries. Because the world population is predicted to increase from 5.3 billion to 8.2 billion in the next 35 years and the expectation is that 90 percent of this increase will take place in developing countries, the sources of non-commercial energy mentioned above will be used up at an ever increasing rate and the demand for oil by the developing countries will increase concomitantly and the only way for them to meet the increased demand for liquid fuel brought on by accelerating urbanization and industrialization is to import it, or develop whatever indigenous energy resources they are fortunate enough to have, including heavy crude and tar sands.

HEAVY CRUDE AND TAR SAND RESOURCES

The most obvious and compelling arguments for developing the world's heavy crude and tar sand resources are their great magnitude, their widespread occurrence, and their availability. Unfortunately, there is still not reliable estimate of the upper limit of the heavy oil and bitumen resource base in the world. Only a few countries, have made reasonably good resource estimates, however, these few account for approximately 3–4 trillion (1012) barrels in place and it is not unreasonable to expect that another 2 trillion (1012) barrels exist in the rest of the world. Suffice it to say that the size of the combined resources of heavy oil and bitumen are believed to be equal to, or perhaps even greater, than the quantity of light conventional oil when measured on an equivalent basis, i.e., initial oil-in-place. And let us not forget that the properties of heavy oil and bitumen vary in the same way as light oil, i.e., there are high sulphur and low sulphur bitumens and heavy oils, high metals and low metal bitumens and heavy oils and high wax and low wax bitumens and heavy oils.

This variation of properties has made it difficult to find a universal definition for what we call heavy oil and bitumen. However, there seems to be a wide acceptance for the definition published by the UNITAR/UNDP Centre for Heavy Crude and Tar Sands based on viscosity at reservoir temperature and density (Figure 1). Although it is recognized that some modification of these definitions may be necessary to accommodate the types of heavy oils found in China. Until a consensus is reached on the definitions for these resources no accurate Statistics can be compiled.

Because the knowledge base of heavy oil and bitumen resources continues to be deficient, it is necessary to assess all evidence, including seepages and "Shows" to determine if they are indicative of larger supplies hidden from view. Each developing country is encouraged to evaluate any heavy oil and tar sand deposits within its territorial boundaries. To assist in the identification of potential prospects for development in developing countries the Centre conducted a survey of the relevant published data of 197 countries and classified them as (1) having production, (2) a known but undeveloped resource, or (3) "seepages" or "shows" of heavy oil or bitumen. The results (published in issue number 29 of the "Heavy Oiler" April 1989) revealed that 93 countries show some evidence of the presence of heavy crude or natural bitumen. Fifty-one having both heavy crude and bitumen, 22 having heavy oil only and 20 natural bitumen only. Of the 73 countries with heavy crude of some kind, including "seepages" and "shows", 43 are currently producing or have produced it in the past. Of the 71 countries with reported natural bitumen in the form of deposits "seepages" or "shows", 18 are currently working the deposits or have worked them in earlier times mostly for asphalt or bitumen for road paving. We know of only three countries that have adequately evaluated their heavy oil and bitumen resources. These same three countries, Canada, Venezuela, and the United States, also lead the world in developing technology to extract and process these resources into an acceptable refinery feedstock at reasonable prices and without creating significant environmental damage.

Commonly, the heavy crude and bitumen resources in developing countries are relatively small and no skilled tradesmen, technicians, or engineers are available to bring them into production. In many cases no infrastructure exists to support development and whatever scarce capital there is has to be husbanded to pay for the imports necessary to sustain life itself. It is clear that such countries with the money, technology, and know-how to do the job. One of the roles of the Centre is to bring these two groups together to facilitate the transfer of the necessary knowledge and technology.

ROLE OF UNCONVENTIONAL OIL

At the Heavy Crude Centre we believe that the role of unconventional oil, or synthetic oil, derived from heavy crude and tar sands, is to supplement and eventually replace conventional oil supplies so that there will be time to conduct the scientific research and technology development necessary to product a commercially acceptable non-polluting alternative fuel to crude oil, and its products. Unfortunately, a smooth transition from fossil fuel to solar fuel is less certain than most of us would like to believe and the social forces that are building against the use of fossil fuel may take effect before a satisfactory replacement is available and could produce a new energy crisis if the fossil energy industry is forced to stop exploring for conventional oil, stop mining for coal, and stop developing the technology needed to produce heavy crude and bitumen from tar sands.

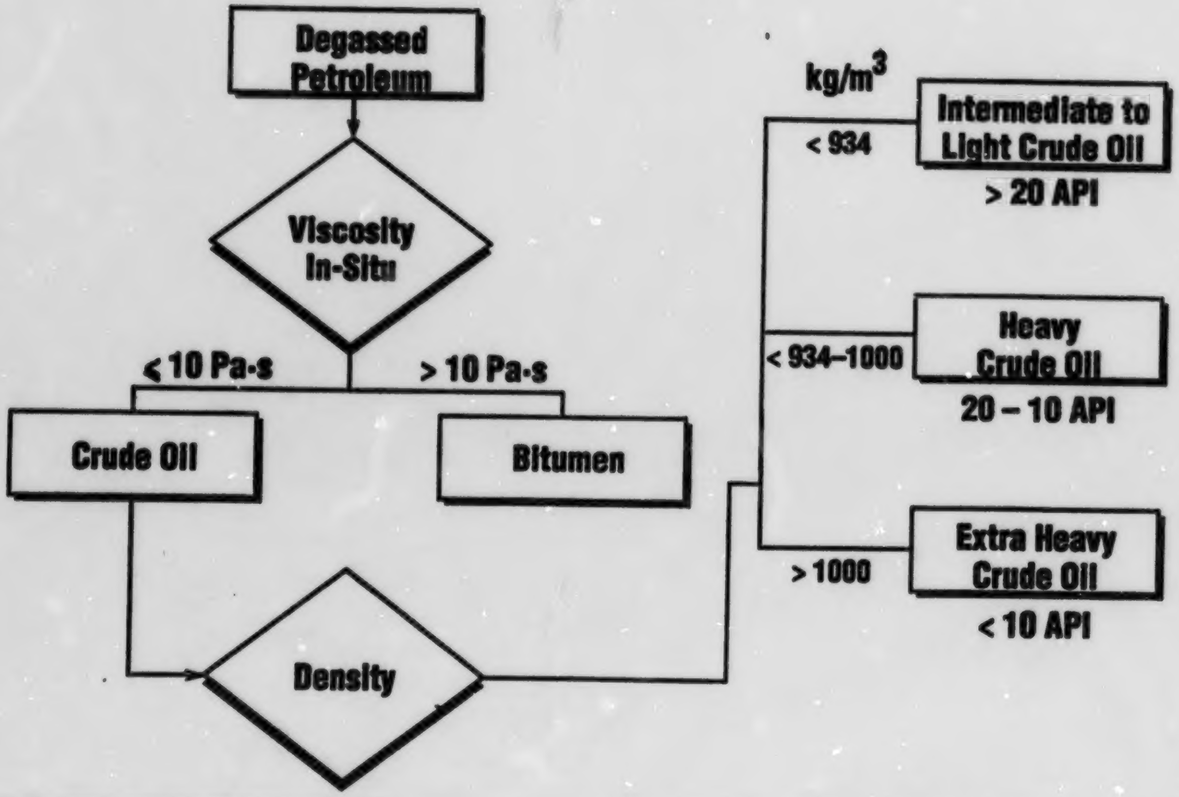
It is therefore very important to continue with the research and development of technology, for the production and upgrading of heavy oil and bitumen and symposia such as this will play a large role in achieving that objective.

ENVIRONMENTAL CONCERNS

I would be remiss if I did not mention some of the environmental factors that may constrain the attainment of this goal.

There is today a widespread believe or perception that global environmental degradation is now threatening human well-being and, perhaps at worst, the survival of life on our planet. Many of the "green house" effects are being blamed on the burning of fossil fuel. The two most evident consequences of which are acid rain and the build-up of carbon-dioxide in the atmosphere, which may eventually lead to global warming and its consequences such as shifts in climatic belts and rising sea levels. These concerns for the global environment have now convinced world leaders that early multinational action is necessary, to prevent irreversible changes in the world's climate. The dilemma was addressed in a United Nations report on into *Environmental Perspectives to the Year 2000* which defined the collective goal for energy as "The provision of sufficient energy at reasonable cost, notably by increasing access to energy substantially in the developing countries, to meet current and expanding needs in ways that minimize environmental degradation and risks, conserve non-renewable sources of energy and realize the full potential of renewable sources of energy"..."The difficulty is to determine up to what level the damage costs of polluting fossil fuels should be accepted and how much to invest in scientific research to develop clean technologies."

Bitumen Definition UNITAR/UNDP



Degassed Petroleum

Viscosity In-Situ

< 10 Pa·s

> 10 Pa·s

Crude Oil

Bitumen

Density

kg/m^3

< 934

Intermediate to Light Crude Oil

> 20 API

< 934–1000

Heavy Crude Oil

20 – 10 API

> 1000

Extra Heavy Crude Oil

< 10 API

GENERAL SESSION
Overview

CURRENT TRENDS IN CANADIAN TAR SANDS RESEARCH AND DEVELOPMENT

D.A. Redford
Alberta Oil Sands Technology and Research Authority

ABSTRACT

Currently Alberta produces ~32,000 tonnes/day of synthetic crude from mined oil sands plus about an additional 21,000 tonnes/day of raw bitumen from in-situ recovery projects. It does, therefore, have the technology to produce from a substantial portion of the deposits. The economics of recovery for new capital expansion are however marginal at long term oil price trends. This, together with the emphasis on environmental concerns, has directed new research and development towards new recovery technology which is both more cost effective and environmentally friendly.

In the mining area, new developments have concentrated on reducing mining cost (50% of plant costs) through the use of dredging and the resulting extraction technology required to handle dredged oil sands. New efforts are also being made to eliminate the tailing ponds both for environmental reasons and to eliminate the cost of selective mining of the overburden for the purpose of obtaining dyke-building material. Research is also directed towards the use of borehole mining technology thus greatly increasing the resource exploitable by mining methods.

In the in-situ area, the two major cost areas are access to the resource and the cost of energy. New research efforts are therefore directed towards better and cheaper access to the resource and the use of technologies which are more energy efficient. Some of these technologies are shaft and tunnel access (SATAC), the use of gravity drainage to horizontal wells, improved drilling technology, steam- or gas-assisted gravity drainage to horizontal wells, top down processes, and the use of combustion in thick reservoirs.

The paper will review the above emerging technologies and indicate the author's view of the direction and potential of each.

INTRODUCTION

In 1975, when AOSTRA was founded, very little oil was being produced from Alberta's immense oil sands deposits. One plant was operating in the surface minable Athabasca oil sands using the well-known Clark hot water process. This plant had serious environmental and conservation limitations and the process was only applicable to about 5% of the total oil sands resource. The task of AOSTRA, therefore, in its first 15 years, was to develop the technology that would enable industry to exploit the other 95% of the resource and to develop more environmentally friendly technology which, at the same time, resulted in high recoveries and high conversion to consumable productions.

AOSTRA and industry, working together, have been very successful in developing such technology over the past 15 years. So much so that today large portions of most of the deposits can be exploited, bitumen conversions are much higher, recoveries are much better, and environmental concerns have been addressed. Today, nearly one-third of Alberta's oil is produced from oil sands and this number must continue to increase as conventional production declines if Alberta and Canada are to maintain petroleum selfsufficiency.

While AOSTRA and the industry have made major strides forward in technological development, the cost of producing oil from the oil sands is marginal when compared to the long term historic price for crude. The challenge facing the industry today is to cut costs such that oil from oil sands will be competitive given this long term historic price trend. This can only be achieved through technological innovation, both in terms of improvements to existing technology and increasingly through break-out technology and paradigmatic changes in thinking which result in dramatically different technology.

This paper outlines the current technology in oil sands recovery as developed over the past 15 years and uses that as a jumping off point to explore new research trends and directions which, it is believed, will lead to major cost reductions as well as improved recovery and resource utilization.

THE MINABLE OIL SANDS

Currently, about 10% of the Athabasca deposit can be recovered by surface mining using the current cut-off criteria of one meter of overburden removal for each meter of pay thickness. Still this is 4 billion metric tonnes of synthetic crude recoverable by ERCB (Alberta Energy Resources Conservation Board) estimates.

The current practice is to drain the muskeg with large drainage ditches, strip the muskeg in the winter and stockpile it for future revegetation, remove the overburden using front-end loaders or bucket wheel excavators and large 90-tonne off-road dump trucks, mine the oil sands using walking draglines or bucket wheel excavators, move the ore to processing by belt conveyors, process the ore using the Clark hot water process followed by dilution centrifuging of the froth, and disposal of the tailings in giant disposal ponds which continue to grow.

The cost of producing oil by this process is about 50% in the mining, including the cost of selectively mining the overburden to produce dyke building material to retain the tailings, 10% in the extraction, and 40% in the subsequent upgrading of the raw bitumen to synthetic crude. While costs for the process have continued to decline as we move up on the learning curve, dramatic cost savings will only be achieved by addressing the main cost centre which is mining.

Oil sands production is a giant solids moving problem. For each tonne of synthetic oil produced, 14 tonnes of oil sands are moved and processed. At the current production of ~32,000 tonnes/day of synthetic crude, 450,000 tonnes of ore is handled each day plus up to an equal amount of overburden.

It has long been known that the cheapest way to mine and move large amounts of solids is by dredging and hydraulic transport. In the past this method has been rejected for oil sands since it would produce an over-conditional ore which would not separate well in the hot water process. It has also been rejected for the overburden removal due to problems at the disposal site and the need to selectively mine the overburden for dyke building material. Current step out thinking, however, is to concentrate on handling the ore as produced by dredging and hydraulic transport and move out of the limitations imposed by the hot water process. This has led to the cold water process.

The cold water process takes the ore directly from a dredging and hydraulic transport operation and floats the bitumen off without heat or addition of caustic (the process will operate as low as 5°C). The froth produced, while richer in fines and water than that from the hot water process, can be handled in similar equipment while the water readily separates from the tailings thus eliminating the requirement for large tailings ponds and enabling a large portion of the water to be recycled to the dredging operation. The cold water process, therefore, affects all aspects of mining, extraction, and tailings disposal and, therefore, has the potential of a 40% reduction in the cost of producing synthetic crude from the surface minable portion of the Athabasca deposit.

HYDRAULIC MINING THROUGH SMALL DIAMETER BOREHOLES

For about 10 to 15 years, the technology has been developed for mining oil sands and other ores such as uranium through small diameter boreholes.[1–15] The product from such a process would be ideally suited as feed for the cold water process and thus the advent of the cold water process has rekindled interest in this mining technique.

In hydraulic mining through small diameter boreholes, a borehole (~40 cm in diameter) is drilled down through the pay and the well cased to the top of the pay. A hydraulic mining tool is then lowered consisting of a controllable (vertical and azimuth) water jet. The water jet hydraulically mines the ore while the slurry pump, typically a moineau pump, moves the resulting water and ore slurry to the surface. If the cavity roof is supported by gas, say air or nitrogen, then the jet can cut a cavity 10 to 20 meters in radius. Recent suggestions are to support the roof cavity with water but this requires that the jet be extendible to the cavity wall. Recent advances in jet drilling make this possible.[17–23] In these instances the cavity may be even larger. This type of mining extends the depth to which ore can be recovered much deeper than the 50 meters obtainable by surface mining. In theory, any depth can be achieved limited only by the cost of moving the ore to the surface. It is believed that depths of several hundred meters are very practical and perhaps as much as 700 or 800 meters or more. This would enable mining of oil sands ore from major portions of the Athabasca deposit, the richest oil sands in Canada, as well as possibly from other deposits. It would also enable the mining of ore from other deposits around the world such as the Marl or "Marga" deposits of Cuba which form thick rich pays about 200 meters from the surface.

RETORTING

One approach that has been suggested for surface mined oil sands, but which also could be applied to hydraulically mined ore, provided the water content could be substantially reduced, is to combine extraction and upgrading in a single process. This is the approach taken in retorting technology such as the AOSTRA Taciuk Process or ATP. Here the ore is indirectly preheated to drive off the water, the ore is then mixed with very hot sand to crack the bitumen and recover the distillable products, with the resulting sand coated with coke combusted to burn off the coke and provide heat for the process.

The process has the advantage over other retorting technologies in that it is a single robust operating unit, it provides excellent heat recovery and recycle, it has a very simple feed mechanism, and it handles fines very well. Retorting technology provides a dry tailing which is environmentally benign. In addition, it eliminates the tailings ponds and the need for selective mining of the overburden, thus sharply reducing mining costs.

The products of the ATP are similar to that coming from a fluid coker and can be further hydrotreated in conventional catalytic hydrotreaters. Nevertheless, the ATP, as with all retorting technologies, limits upgrading to carbon rejection rather than hydrogen addition technology and thus, in part, is a trade between a more environmentally friendly technology and extraction technologies which have the potential for high product conversion and hence greater resource utilization and conservation.

UPGRADING

Bitumen is a very viscous crude which is difficult to transport. To provide a readily pipelineable product which will give a high yield of transportation fuels, the hydrogen-carbon ratio must be increased. This may be done by carbon rejection of hydrogen addition.

In the first upgrading plants in Alberta, carbon rejection was the preferred route as it was a well-proven process. Thus, the Suncor plant was built with delayed cokers and the Syncrude plant with fluidized cokers. Both followed these primary processes with catalytic hydrotreating in a second process step.

The second generation of upgrading, which is just now being introduced, is based on hydrogen addition as part of the primary conversion. Here, hydrogen is added during the cracking process thus resulting in much higher liquid yields. A number of processes have evolved, both catalytic such as LC-Fining, H-Oil and ARDS (Atmospheric Residue Desulfurization), and non-catalytic such as CANMET and VEBA COMBI-Cracking. Currently, Syncrude is operating a LC-Fining Unit as an addition to its upgrading operations while a plant which will use the H-Oil process is under construction at Lloydminster and the ARDS is operating at a refinery near Regina, Saskatchewan. The OSLO Company has proposed using the VEBA COMBI-Cracking Process for its proposed new plant.

The third generation of upgrading processes which are currently in research laboratories, or even just wish lists in the minds of research managers, will see conversions pushed much higher, approaching

100%, and gas makes dramatically reduced. This will be achieved by better catalyst design and utilization and by control of the formation of coke and coke precursors. This will all result in much higher yields of liquid products which will give greater amounts of transportation fuels.

An additional trend in upgrading research is to tailor-make a synthetic crude which would give a higher yield of desirable transportation fuels (increasingly this desirability is being pushed by legislation requiring more environmentally friendly fuels). For example, at present, due to the high aromatic content of synthetic crude, the cetane member of diesel from this crude is too low and the crude does not make a good jet fuel. This results in refineries discounting the synthetic crude $10 to $20/tonne as compared to a conventional crude of equivalent gravity. If the primary conversion and/or subsequent hydrotreating yielded lower aromatics, the resulting synthetic crude would have higher market value.

UNDERGROUND ACCESS

Rather than bringing the ore to the surface or accessing the resource from surface drilled boreholes, one approach is to sink shafts until they are just below or above the resource, send out tunnels or "drifts," and then access the resource by drillholes which travel only a few meters (~15) before they contact the resource. This has been successfully done at Yarega in the Soviet Union and at AOSTRA's UTF (Underground Test Facility) in Athabasca. At Yarega, tunnels are both above and below the resource and recovery is by injecting steam into numerous short small diameter wells drilled from above with recovery from numerous drain holes drilled from below. The process is essentially a SAGD (Steam Assisted Gravity Drainage) process.

At the UTF site, two technologies have been successfully used. The Chevron HASDrive (Headed Annulus Steam Drive) and steam assisted gravity drainage using horizontal well pairs. In the HASDrive process, a hot horizontal well, heated by steam, is used to maintain hot mobile communications through the hot annulus along the side of the horizontal well. Principal recovery is by steam drive between vertical injectors and producers placed at either end of the HASpipe. In the SAGD approach, parallel horizontal wells, one above the other, are drilled ~3 to 5 meters apart near the base of the pay zone. The interval between the wells is heated by operating both wells in a hot finger mode (steam down the tubing and back the annulus with communication to the reservoir through sand exclusion liners). Thereafter, steam is injected only into the upper well and fluids collected from the lower well in a SAGD process. The production well is operated on enthalpy control such that only condensed steam and bitumen are produced (i.e., much as a steam trap operates). The SAGD process, when operating in this way, gives very high recoveries at low steam oil ratios and with good production rates.

The SAGD process operating from shaft and tunnel access facilities is estimated to give some of the lowest-cost bitumen recovery currently achievable from Alberta's oil sands.

IN SITU RECOVERY FROM SURFACE WELLS

Currently Alberta produces ~21 tonnes/day of bitumen in situ from surface wells using two basic technologies. Historically, heat in the form of steam (stimulation and drive) and combustion have been used to recover bitumen and heavy oils around the world with steam by far being the most common heat source used. Its application to Alberta oil sands reservoirs in its traditional forms proved a dismal failure, however, two special processes were successfully developed.

Steam Stimulation Above Fracture Pressure

In this process, which was developed for the Cold Lake Deposit, steam at high rates is injected above the fracture pressure into the oil sands through wells equipped with cased through and perforated completions. Because of tectonic forces in the area, the vertical fractures mainly orientate perpendicular to the nearest mountain range. The steam entering the vertical fractures heats the oil along the side and in turn is cooled and condensed. Near the well, the fracture is hot and the heated oil limits fracture leak off. Further from the well, the condensed steam is cooler and fracture leak off increases so that after about one month of steam injection, the characteristic dumbbell shaped distribution of water saturations is formed with the heat concentrated within this area in a vertical fracture zone near the well. When the well is put on production, the water is therefore further from the well pushing the intervening heated bitumen to the well. Typical production periods are three or four months with 8 to 10 production cycles occurring before the area is depleted. In the thicker pays of Cold Lake, steam oil ratios of 2 to 3 are achieved at CDOR's (calendar day oil rates) of ~10 tonnes/well/day and overall recoveries of ~17%.

Interwell Pressure Cyclic Steam Drive

In those areas of the oil sands deposits where injectivity below fracture pressure exists in the lower part of the pay, an interwell pressure cyclic steam drive process has been developed. In this process, hot water followed by steam is injected to achieve hot communication across the base of the deposit. The production well is then choked back and pressure allowed to build up in the basil zone producing a hot high pressure pancake or hot plate across the base of the deposit. Steam injection is then cut back and production increased depleting pressure and fluids form this zone. The process is then repeated three or four times with the hot zone progressively moving up the deposit and depleting the overlaying bitumen. In good sections of the Peace River deposit, recoveries of 50% or more are achieved at steam oil ratios of about 4 and CDOR's of ~7 tonnes/day/well.

Research Trends

In in-situ recovery, there are three main cost factors in order of importance: the cost of energy, the producibility of wells, and the cost of access to the bitumen. New thinking is taking place in all three areas.

In the area of energy costs, the trend is to lower temperature processes — perhaps, why use heat at all? McKay,[24] Pratts,[25] and Vittoratos[25] have suggested that our traditional concept of what is flowing in the reservoir may be incorrect and they support this with field and laboratory observations. If this is so, and we understand this phenomenon of combined oil and water flow better, perhaps we can engineer our processes to take advantage of this apparent increased low temperature mobility. Farouq Ali and others have done extensive work on immiscible use of CO_2 and noted that mobilities of bitumen even at modest pressures can be greatly enhanced by saturating with CO_2. Then too, there is the promise of altering the oil by biological action. All of these approaches, coupled with improved well productivity and formation access, give promise of substantially lower production costs.

Combustion has long been known as the cheapest way of heating a reservoir and providing drive energy. The difficulty in using combustion has been in distributing the heat and drive energy to achieve conformance and in obtaining control of the process. For these reasons, to date, combustion has mainly been successful in thin pays or pays with a dip thus promoting control by gravity segregation. Nevertheless, combustion still promises a cheaper energy source than steam; however, new approaches are needed to address the conformance problem to enable the process to work well in thicker pays.

The second most important cost factor is well producibility. The advent of horizontal wells has greatly improved the producibility of wells and enabled some novel recovery concepts, but the cost of placing horizontal wells is a major concern. A second approach that is being considered is to let the formation come. The greatest resistance to flow is near the well and this is especially true for viscous fluids. The advent of downhole slurry pumps has facilitated the production of sand-oil-water slurries. Therefore, why not use a lower temperature recovery process and couple this with a production scheme which permits the formation around the production well to be produced along with the production fluids? The development of the cold water and Taciuk processes facilitate treatment of the resulting bitumen-saturated solids at the surface.

While it would be nice to have communication across the bottom of an oil sands deposit, in many parts of Athabasca the communication is at the top. This is also true in Cold Lake after initial recovery has occurred. In addition, many heavy oil deposits are underlain with thick sections of mobile water. These conditions have led to interest in top down processes, sometimes in combination with lower temperature processes and the use of horizontal wells.

One example of a successful top down experimental process was the Tangle Flags project in Saskatchewan. In this project, a horizontal production well is placed near the oil water contact in a heavy oil reservoir with a thick section of bottom water and a strong bottom water drive. Steam is then injected into the top of the pay through vertical wells. The production well is then produced with a back pressure equal to the pressure of the bottom water drive and a gravity stabilized vertical steam drive occurs from the top to bottom of the reservoir. Following steam breakthrough to the horizontal well, large amounts of additional oil are produced by a Steam Assisted Gravity Drainage (SAGD) process. The project has produced large amounts of heavy oil at good production rates and steam oil ratios and minimum coning of the bottom water into the producer.

Other top down processes could be considered. In the Tangle Flags type reservoir, it has been suggested that the steam might be replaced with gases that reduce the viscosity of the oil or with low vapour pressure solvents. In Cold Lake, following initial fracture-steam-stimulation recovery, and particularly in Athabasca, the use of gas above, particularly those which reduce bitumen viscosity and heat below in a top down process has been suggested. The concept is that the gas above would provide drive energy while the apparent low viscosity flow of bitumen and water at modest temperatures would occur below.

The third major cost factor in in-situ recovery is access to the formation. Shaft and Tunnel Access approaches and horizontal wells provide greatly improved formation access but costs are still far too high. As an example, for the Tangle Flags project to go commercial, cheaper drilling and completion of the horizontal wells is required.

Several new approaches show promise of substantially reduced drilling and completion costs. Jet drilling[16–23] of soft formations such as oil sands has been shown to be rapid and efficient; however, further development work is required to prove the technology reliable and predictable, to improve the direction and control, and to demonstrate long distance drilling in field situations.

A second approach is a "case while drilling" concept. This would markedly reduce rig time and drilling costs and provide an overall cheaper completed well. Jet drilling concepts may be one way of achieving this.

A third approach is to eliminate casings and sand exclusion all together and fill the horizontal drilled path with coarse highly permeable sand. This concept of sand filled channels[26] eliminates the requirement when drilling that angles of curvature must be gentle enough to enable placement of casing. A right angle or ultra-short radius horizontal drill hole from a well can thus be considered using flexible drilling strings or small diameter drill pipe which can be bent around a sharp turn.

CONCLUDING REMARKS

Tremendous progress has been made in the past 15 years on development of technology for recovery of bitumen and extra heavy oil resources, but costs in general are high and profits marginal. The next generation of technology advancement will see new concepts employed which address the major costs centres. This will often require break-out technology which forces us to step out from our long held beliefs. As researchers, the years ahead are challenging and exciting ones.

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REVIEW AND PROSPECT OF HEAVY OIL THERMAL RECOVERY TECHNOLOGY DEVELOPMENT

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In the last decade, the Research Institute of Petroleum Exploration and Development (RIPED) created a heavy oil thermal recovery laboratory, which has a complete set of physical models and a multiphase thermal simulation software package. For the reservoir engineering studies and the development of wellbore insulating equipment and techniques, the Heavy Oil Thermal Recovery Department was also established. Currently, there are more than 30 special research subjects, 17 development plans for thermal recovery and steam flooding pilot projects, most of which are underway. These accomplishments have played a pioneer role and guide to the development of heavy oil reserves in China.

The technical cooperation between RIPED and AOSTRA (Canada) has also achieved satisfactory results in the following five special projects, namely: the economic evaluation method for thermal recovery, steam foam physical modelling study, steam foam numerical simulation study, steam injection physical modelling study, and heavy oil phase equilibrium physical experiment research. In addition, there was the first China-Canada Heavy Oil Technology Symposium successfully held at Zhuo Zhou, in October 1987. Looking toward the future, the thermal recovery methods will be extensively developed in China, and RIPED will continue to intensify the new research projects in order to develop large scale heavy oil reserves in this country.

REVIEW OF THE TECHNICAL DEVELOPMENT FOR THERMAL OIL RECOVERY

China is rich in heavy oil resources, which were discovered in most of the main sedimentary basins of the country.

According to the standards of heavy oil classification and the thermal recovery screening criteria, the conventional, extra and super-heavy oils were all discovered in China. Currently, the cyclic steam operations have been successfully conducted in more than ten heavy oil fields in Liaohe, Kelamay, Shengli and Nanyang Regions.

In 1982, the success of a cyclic steam test in a first deep well (depth 1,500–1,600 meters) in Gaosheng field opened up the page to heavy oil development history. Towards the end of 1989, 3,600 steaming cycles were conducted on more than 1,000 wells with depth of 800 to 1,600 meters in the oil fields of Gaosheng, Shu No. 1 District and Huanxiling in the Liaohe Region. The cumulative hot oil production and cumulative steam injection are 11.75 and 10.02 million tonnes respectively. These resulted in cumulation oil/steam ratio of 1.117. In 1990 alone, the steam stimulation on wells will exceed 1,500 cycles, and oil production by thermal assistance will surpass 5 million tonnes. The Liaohe Region has become the largest heavy oil producer by thermal recovery in China.

The steam stimulation technique also has been used for heavy oil recovery in the other three regions. A large scale commercial project has been especially developed in Keramay district No.9.

In 1989, more than 6 million tonnes of heavy oil were produced in China from more than 3,000 cycles of steam stimulation. It is expected that the total heavy oil production from thermal recovery will exceed 8 millions tonnes in 1990, and the scale of heavy oil recovery projects will be further enlarged in this country.

While large scale steam stimulation was becoming popular, nine steamdrive pilot tests were conducted for the different types of heavy oil reservoirs. Some of the steam stimulation projects were converted for steamdrive in order to further improve oil recovery and obtain the field experiences of steamflooding the reservoirs.

Because the result of heavy oil recovery by steam injection is encouraged, the steam injection techniques have been quickly accepted and further developed in China. RIPED, the scientific research center of the China National Petroleum Corporation (CNPC), built a heavy oil thermal laboratory in the early 1980s, which has expanded steadily since. Now it has established the Heavy Oil Thermal Recovery Department, which is responsible for three research tasks: (1) comprehensively studying the technologies for heavy oil development in China in order to establish the strategic research and development plans for heavy oil reserves, and to initiate feasibility studies for thermal oil recovery in the new fields; (2) cooperating with the regional institutes to conduct the designs of development plan and of pilot projects for thermal recovery in the major heavy oil fields; (3) to develop the new techniques and methods for heavy oil recovery. Moreover, to conduct the fundamental research.

RIPED is a research institute which has been playing a pioneer role in the technical development of heavy oil thermal recovery in China. Similar research organizations were also established in the Liaohe, Xinjiang, Shengli and Nanyang fields to develop certain operational techniques suitable for the local practice.

In the 1980s, thermal recovery technologies developed at an accelerated speed in China, mainly:

1. An abundance of experiences were obtained from the heavy oil reservoir studies for various types of reservoirs. Some examples include the 3-D reservoir description, which was successfully accomplished by using simulation softwares; the standards of heavy oil classification; and thermal recovery screening criteria for the Chinese crudes were established.
2. RIPED has a complete set of physical modelling equipments for steam injection. These have been used for simulation of steam stimulations and steam drives in the heavy oil fields. The purposes are to study parameters such as: well pattern, well spacing, perforation intervals, injection rate as well as pressure, and geological factors on the steam injection response. In the Keramay field, another set of physical modelling equipment was also developed.
3. The numerical simulation was the most accepted technology in the last decade. The softwares from the SSI of USA and CMG of Canada were utilized for reservoir studies. Moreover, RIPED has its own thermal recovery softwares; and the workstation for thermal recovery simulation, especially several sets of microcomputer softwares for thermal recovery, have been extensively used in the field.
4. With the approaches mentioned above, RIPED completed the project design for thermal oil recovery in five fields, the feasibility study for thermal recovery for three fields, and nine pilot project designs for steamdrive. These accomplishments certainly guide the practice and development in the heavy oil fields, also we have primarily accumulated valuable experience from the studies and designs.
5. In order to prevent wellbore heat losses in the deep steam injection wells with depths of more than 1,600 meters, the heat insulating tubings were used extensively in these wells. Such tubes were commercially fabricated in China with the same quality as that of the imports, but the costs were much lower than the latter.
6. Well completions by using prestressed casings could prevent casing damage from thermal expansion. This completion technique has been broadly used in deep and shallow wells for steaming operations.
7. Producing heavy oil from thermal recovery fields requires certain types of pumping units and rod pumps. The long stroke pumping units of types 12 and 14 and chain pumping units were employed in several hundreds deep wells.
8. Gravel packing technology with wire wrapped screens for sand control has been widely used in heavy oil wells with sands problems. This method

has better field results and is more suitable for thermal operation wells.

9. Steaming operations require steam generators to produce high temperature and pressure steam. Currently in China, there are more than 100 steam generators in field operation, and two manufacturing plants can produce complete sets of equipment to meet the demands.
10. The technology of surface oil and gas transportation, pipeline heat insulation, fluids metering and dehydration has been improved in the field.

As a whole, in the past ten years, we have achieved certain success in the development of thermal recovery technologies, but we still need further improvement in the following subjects, such as: the practical experience for steamdrives, the reservoir performance monitoring technique for steam injection, and the accurate metering technique of steam quality and flow rate for multi-well steaming operations.

THE HEAVY OIL RESEARCH SUBJECTS IN RIPED

RIPED, the research organization of the China National Petroleum Corporation (CNPC), is responsible for scientific research of petroleum exploration and development. There are eight departments and three research centers in RIPED, namely: the department of petroleum geology, oilfield development, well drilling technology, oil production technology, heavy oil thermal recovery, oil field chemistry, enhanced oil recovery, and petroleum mechanics. The research centers are geology experiment, seismic, and computer. Currently, 1,500 technical researchers are employed including 300 senior research staff.

The Heavy Oil Thermal Recovery Department is mainly responsible for the research tasks of heavy oil development, the Geology Research Department for the exploration research of heavy oil reserves, and the Oilfield Chemistry Department for the chemical agents study.

THERMAL RECOVERY DEPARTMENT

Softwares and Hardwares

Numerical simulations

1. Several sets of three-dimensional, three-phase numerical simulation softwares can be used for steam injection, including foam additive assisted steam flood software and the CMG's Stars software;
2. Softwares developed by RIPED can be used by field personnel:
   a. three-dimensional, three-phase numerical steam model
   b. wellbore heat transmission numerical model
   c. reservoir district dividing software
   d. data and figures processing software
   e. economic-analysis software for steam injection

This software package was developed by using the advanced numerical solution procedures with high accuracy and stability for high-speed calculations. These programs not only can save computing time but also be used easily on mainframe or on personal computers. For instance, this package has been used broadly in the field.

Physical simulations

1. *High temperature and high pressure three-dimension scaled physical model.* With this model, our studies include: simulation of several heavy oil reservoirs for both steam soak and steamdrive; optimization of the well pattern, well spacing, completion interval and injection parameters for steaming operation; and investigation of the oil recovery from reservoirs with steamflood at different oil viscosity and different formation thickness.
2. *High temperature and high pressure one-dimension physical model.* With this model, we simulated the displacement efficiency of more than 10 heavy oil reservoirs for cold water, hot water and steam injection. Also we studied the effect of enhanced oil recovery with different chemicals and foam additives added to the steam and hot water.

3. *High temperature relative permeability apparatus.* Using this apparatus, the relative permeabilities of oil-water and oil-steam on cores from more than 10 heavy oil pools were measured. We also had sensitivity studies of the hot water and steam in reaction with cores containing clays.
4. *High temperature and high pressure rotary viscosimeter and spinning drop interfacial tensiometer.* With these meters, we investigated the rheological characteristics and viscosity changes of heavy oil and paraffin oil with high-pour points.
5. *Reservoir rock thermal-physical property measurement instruments.* Most of the reservoir rocks from the heavy oil fields in China were measured. The tested parameters are heat conductivity, heat capacity and diffusivity of barrier beds.
6. *Wellbore heat transmission physical model.* With this model, we measured the overall heat transfer coefficient for different insulated tubings and fluids in the wellbores. The results could be used as a reference for selecting the insulation materials and completion methods for steam injection wells.
7. *Heat insulating fluids test instrument.*
8. *Other experiment equipment.*

COMPREHENSIVE RESEARCH RESULTS PERFORMED BY RIPED

1. China's standards of heavy oil classification, and the screening criteria for steam soaking and steamflooding the heavy oil reservoirs.
2. Technical strategy study for heavy oil steam injection recovery.
3. Heavy oil thermal recovery planning study.
4. Heavy oil reservoir geological characteristics study.
5. Wellbore heat insulation project and feasibility study for steam injection in the deep wells.
6. Reservoir numerical simulation software package for steam injection.
7. Development strategy for heavy oil thermal recovery technology.
8. The technical study on the steam stimulation technology for heavy oil reservoirs.
9. The technical study on the steamflooding technology for heavy oil reservoirs.
10. Study of the economic evaluation methods for thermal oil recovery.
11. Others.

HEAVY OIL-STEAM INJECTION PROJECT DESIGNS BY RIPED

Cooperating with the regional field authorities, RIPED finished two large development project designs for steam injection in the Gaosheng and Karamay No. 9 fields. The oil production from each field reached a million tonnes per year. Also, the other three steam injection projects have been on production according to the schedule.

Working in close cooperation with the field authorities, RIPED completed nine pilot project designs for steamdrive in six different heavy oil reservoirs. These were: (1) huge thick formation heavy oil reservoir, (2) multi-layer thin-bedded heavy oil reservoir, (3) multi-layer middle-thick heavy oil reservoir, (4) single-layer thin-bed heavy oil reservoir, (5) heavy oil reservoir with bottom water, and (6) heavy oil pool with edge and bottom water.

For three newly discovered heavy oil fields, the feasibility study of steam injection for reserves development was completed. For some post-waterflood, medium heavy oil reservoirs with high content of paraffin and asphalt in the oil, the feasibility study for improving such oil recovery by heat injection was also conducted. As a whole, RIPED has accumulated valuable experience from steam injection project designs for various types of heavy oil reservoir. This know-how could further help field operations.

TECHNICAL COOPERATION BETWEEN RIPED AND AOSTRA

The exchange of technical information between RIPED and AOSTRA began in 1985. On the basis of friendship and confidence with each other, the three-year technical cooperation agreement was carried out from May 1986 to May 1989. This successful cooperation has produced fruitful results of benefit to both sides and could be a good example of international cooperation for development of heavy oil reserves

There are six projects in the technical cooperative agreement.

1. In October 1987, the first China-Canada Heavy Oil Technology Symposium was held successfully at Zhuo Zhuo, China. In the meeting, scientists and engineers from the two countries enthusiastically and amicably exchanged ideas and experiences in heavy oil thermal recovery. From that was created a precedent for the second China-Canada Heavy Oil Technology Symposium.

   This symposium was organized and sponsored by RIPED and AOSTRA, co-sponsored by Liaohe Petroleum Exploration Bureau and Xingjiang Petroleum Administration Bureau of China, and the Department of Economic Development and Trade of Alberta, Canada.

   There were 109 Chinese representatives from 23 organizations such as: CNPC, oil fields, petroleum universities and institutes. Also involved were 33 Canadian delegates and representatives of 23 groups mainly from oil companies, universities and research institutes of Alberta.

   In total, 50 papers and reports were presented at this conference. The Chinese and Canadians published 23 and 26 articles, respectively, and one was from a joint effort. These papers included the fundamental research, reservoir geology, reservoir engineering, pilot tests, well drilling, well completion, oil production technology, surface facilities and upgrading processes. The proceedings were printed in Chinese and in English.

2. *The research of improving steam sweep efficiency by adding a foam agent.* Since 1987, RIPED engineer J. Li and scientist Dr. Eddy Isaacs of the Alberta Research Council (ARC), worked together to perform EOR research using steam added with foam agent to flood the Chinese and Canadian heavy crudes. They exchanged experimental techniques and presented the results in an article. Now, this study continues to work in our institute. In the near future, we will conduct field tests using the foaming agent investigated by RIPED.

3. *Physical simulation of steam injection for heavy oil recovery.* Since 1988, RIPED engineer G.H. Zhou and an ARC scientist Dr. Tawfik Nasar carried out a physical model study of steam injection in a five-spot pattern to recover super-heavy oil in a Cold Lake reservoir with bottom water. They completed the study and obtained an optimized steam injection strategy.

4. *Heavy oil phase behavior study.* In 1988, RIPED engineer X.D. Zhang and a ARC scientist Dr. Cheng-Tze Fu accomplished phase behavior physical experiments of heavy oil with solution gas. Also they conducted CO_2 solubility study in the heavy oil of Nanyang field, China. The results provided the information for developing this research work.

5. *Economic evaluation method research of heavy oil for thermal recovery.* In 1987, RIPED engineer Q. Jiang stayed in Canada for three months to study economic evolution methods for heavy oil thermal recovery. A new heavy oil economical evolution model was subsequently developed by joint effort. This model was used for economic analysis of a pilot test in the No. 9-3 District, Xinjiang. Based on the results, Jiang and Mr. Frank J. Werth prepared a paper entitled "A Comparative Study of China-Canada Economic Evolution of Steam Injection for Heavy Oil," which was published at the 4th UNITAR/UNDP Heavy Oil Conference in 1988.

   At present, a flexible, fully-functional economic evolution computer software has been developed.

6. *Numerical simulation of steam injection for heavy oil recovery.* During 1987–1988, RIPED engineer Z.M. Yang worked with Mr. David H. Law and Mr. Terry Stone of ARC to develop a numerical simulator in Canada. The model can handle the process of steam injection with adding foam and can predict the reservoir performance. We used the said model to simulate foam injection for No. 9-3 pilot test as an example. The results of these studies were presented at the 4th UNITAR/UNDP Heavy Oil Conference and SPE meeting (paper SPE No. 18421), respectively.

At present, RIPED has a commercial steam-foam software for steam injection studies.

As a whole, the technical cooperation between RIPED and AOSTRA is fruitful and successful. We would like to thank Mr. W.J. Yurko, President of AOSTRA, Dr. D.A. Redford, Dr. C. Hsi and all our Canadian friends for their help and support.

PROSPECT OF HEAVY OIL THERMAL RECOVERY TECHNOLOGY DEVELOPMENT

Although thermal recovery technology for heavy oil has developed rapidly in China, our institute, which is charged with arduous research tasks and provides the service for urgent subjects in the field, must face the new challenges and should speed up technology development for the future.

For steam injection in the 1990s, the process of steamdrive could replace steam soak for heavy oil recovery. Many steamdrive pilot projects will be developed, and some existing steam soak schemes might be converted for future operation.

Some technical problems must be solved in the future, such as monitoring the reservoir performance during steam flooding with various methods to improve the volumetric conformance efficiency for steam; reducing heat consumption; enhancing oil to steam ratio; further decreasing the heat losses in deep wells; and increasing the steam quality in the wellbore of injectors.

It is possible that some post-waterflood heavy oil reservoirs with high pour-point oil, could be candidates for future hot-fluid injection.

Regarding geological conditions in some reservoirs such as huge edge water; multi-layer thin-bedded; and gravel containing sand features, these must be investigated for future considerations.

For some super-heavy oil reservoirs with oil viscosity of more 100,000 mPa·s, it is uneconomical for conventional steam injection, thus, some unusual thermal recovery methods need to be considered.

Of course, for existing steam stimulation projects in the field, we must further improve field practice and enhance oil recovery in these schemes.

In China, the heavy oil thermal recovery technology is in an era of progress. We should accept the challenges to develop new technology and to learn more from steamdrive in the 1990s.

AOSTRA/ARC/INDUSTRY JOINT RESEARCH IN ADVANCED THERMAL RECOVERY

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ABSTRACT

In the next century, as conventional oil supplies diminish, Alberta's reserves of bitumen and heavy oil must play an increasingly important role in maintaining a strong energy industry in Western Canada. Economic production at projected world oil prices requires significant advances in production technology, and a better understanding of important reservoir processes. The AOSTRA/ARC/Industry Research Program provides mission-oriented, multi-disciplinary research aimed at developing advanced thermal processes for the recovery of bitumen and heavy oil.

The AOSTRA/ARC/Industry Joint Research focuses mainly on the non-site-specific and generic problems which are common to much of the industry. The program provides an interface between fundamental and applied industrial research, complements expertise in universities and industry, and aids technology transfer and problem solving. The problems that remain to be solved in order to ensure commercial viability are beyond the capabilities of a single organization. Consequently, there is a need for a collective coordinated effort which focuses on important problems that are relevant to improved production throughout the industry. The AOSTRA/ARC/Industry Research Program is a partnership through which government and industry can combine their efforts in a cost-effective and productive way.

The research is carried out at the Oil Sands and Hydrocarbon Recovery Department of the Alberta Research Council (ARC) by experienced researchers from many disciplines. Currently, there are five projects under the Program, which were designed to address an identified technical need, with both short and longer term objectives and schedules. These five projects are:

- *Process Flow Mechanisms*
- *Conformance Control*
- *Advanced Process Development*
- *Near Well and Production Related Studies*
- *Equilibrium Relationships and Transport Phenomena*

This paper will review these projects in detail highlighting the recent technical achievements for each project. The management and operation of the Program will also be briefly discussed.

INTRODUCTION

The Province of Alberta in Western Canada possesses at least forty percent of the total known global reserves in heavy petroleums. Most of these heavy petroleum resources are bitumens locked in oil sands, and these are geologically estimated to exceed 1.7 trillion barrels. Canada is one of the largest per capita user of petroleum products in the world. As Canadian conventional oil reserves are falling and imports are increasing, Alberta's reserves of bitumen and heavy oil would have to play an increasingly important role in securing Canada's energy supply. However, the Government of Alberta and the oil industry have faced the enormous technical challenges to develop new technologies necessary to unlock this vast hydrocarbon resource in Alberta. The Alberta Oil Sands Technology and Research

Authority, commonly known as AOSTRA, a Crown Corporation of the Government of Alberta, was established in 1975 with a specific mandate of promoting research and development of new technological methods required for the efficient and economic recovery and processing of crude bitumen from the oil sands deposits. This mandate was subsequently amended to extend to including heavy crude oil and enhanced recovery of conventional crude oil. One of the most important early policy decisions of AOSTRA was that AOSTRA would not construct any research facilities of its own, but would make use of existing facilities. When needed, the Alberta Research Council (ARC) would act as the Authority's technical and research arm.

A substantial research program under the auspices of AOSTRA's Institutional Research Program was launched by AOSTRA at ARC to find out effective ways to recover bitumens from oil sands. Much of this research involves substantial funding and a long term commitment, with no guarantees that the financial investment will pay off. Therefore, it is not the type of research activity that industrial laboratories are best suited to undertake. Initially, AOSTRA established an oil sands and heavy oil research centre at ARC that is second to none. On April 1, 1981, AOSTRA and ARC entered a five-year agreement to conduct a joint oil sands research program. Approximately five million dollars were expended annually. The major activity of the program involved investigation of the benefits of various steam additives, such as gases, solvents, and surfactants. The experimental work included the use of physical simulators, the development of numerical models, and the determination of physical parameters. In addition, the physical chemistry of interfacial phenomena and hydrothermal chemistry of fluid/rock interactions were also studied. The research results were offered to the industry under the Industry Access Agreement in 1982, whereby industry could participate in the research program and receive and obtain right of using all the technical information generated under the research program. Over 200 reports and six patents were issued on the research activities during the course of a five year period from 1981 to 1985. A technology and expertise base, composed of both trained personnel and advanced technical hardware, were, therefore, developed at the end of the first five year program.

In order to facilitate transfer of technology to field applications, the second five year joint AOSTRA/ARC/Industry Research Program commenced on April 1, 1986 with the goal to develop and transfer new technologies that will resolve generic field problems associated with the use of steam-based processes for in situ recovery from the heavy oil and oil sand formations in Alberta. The program has been funded at a level of three million dollars per annum and approximately 30 man-years effort. In the following section, each individual project within the Program will be discussed in more detail.

AOSTRA/ARC INDUSTRY RESEARCH PROGRAM (1986–1990)

The objective of oil sands and heavy oil research is to reduce the cost of production. The problems that remain to be solved in order to ensure commercial viability are beyond the capabilities of a single organization. Consequently, there is a need for a collective, coordinated effort which focuses on important problems that are relevant to improved production throughout the industry. The AOSTRA/ARC/Industry Research Program is a partnership through which government and industry can combine their efforts in a cost-effective and productive way. The program also provides interface between fundamental research, which is normally conducted at universities or academic institutions, and applied research, which the industry carries out in field trials. The research itself is carried out by multidisciplinary project teams that include reservoir and chemical engineers, colloid scientists, geochemists, physicists and numerical modellers. Many of the experiments require precision measurements at high temperatures and pressures under static as well as flow conditions. Scaled models and physical simulators are used for larger scale, multidimensional flow experiments, and numerical modelling is employed extensively throughout the program to interpret the experimental results. Currently, there are five projects under the Program, which were designed to address and identified technical need:

Process Flow Mechanisms

The simple relative permeability approach now used in numerical simulations may not be adequate in cases where emulsions occur, where there is viscous fingering due to high mobility contrasts, or in regions where high temperatures or concentration gradients exist due to heat and/or mass transfer. The main objective of this project is to identify flow regimes for which conventional relative permeability concepts are inadequate, and in developing flow models which better represent such regimes, both in the laboratory and in the field.

Advanced models of steam flood behavior were developed through analysis of laboratory steam corefloods by a unique combination of tools: x-ray computed tomography (CT), which provides spatial and temporal fluid saturations for complex coreflood geometries, as shown in Figure 1, petrographic image analysis (PIA), which is used to acquire quantitative data on core structure at the pore scale; a large scale heat transfer cell which provides data on heat transfer mechanisms; and a multi-component simulator which is used to verify mobilization theory at the core scale as well as the field scale.

A series of steam floods in a homogeneous sand pack showed that capillary forces controlled fluid saturations at the core scale. By scale-up through numerical simulation it was observed that capillary forces may have a significant impact on production at the field scale.

A second series of corefloods examined steam flow through a central water filled channel surrounded by an annual oil sand medium, a steam drag geometry. The CT image data showed that the steam propagated rapidly along the channel. This was immediately followed by thermal expansion of the bitumen which restricted flow. This restriction produced a sharp rise in pressure drop, as predicted by numerical simulation (Figure 2). The steam zone subsequently expanded laterally into the oil sand medium with a corresponding decline in pressure drop.

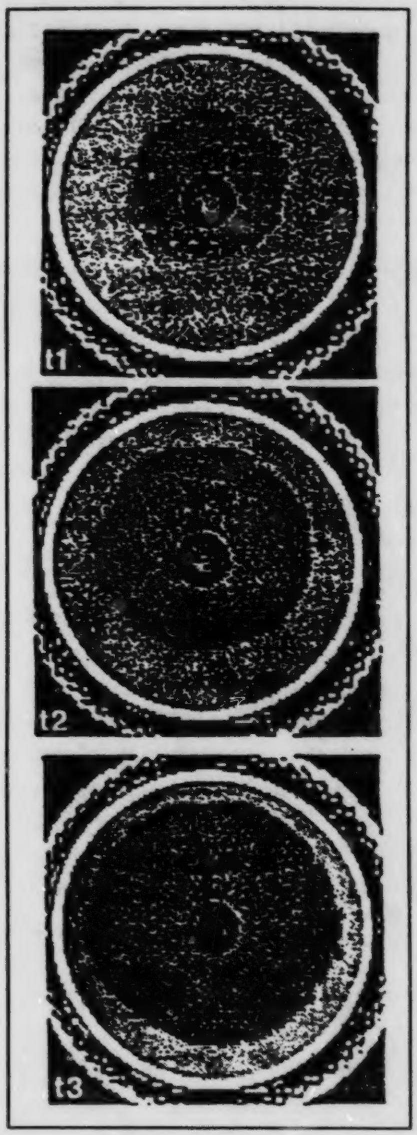

Figure 1. A time sequence of computed tomography (CT) images shows the symmetric expansion of the steam zone about the communication path in a steamdrag coreflood. The steam zone is seen as the dark area; it is surrounded by the unmobilized zone represented by the lighter area.

Conformance Control

Unstable flow phenomena, such as fingering and fluid segregation, and reservoir heterogeneities can result in poor reservoir conformance in many thermal and conventional recovery processes. The objective of this project is to develop processes and injection strategies that would modify and control conformance in reservoirs.

The main project priority is the development of strategies for improving the long-distance propagation of foam in the reservoir. In addition, scoping studies were carried out on the use of emulsions and gels as alternate techniques for controlling conformance. A paper by Dr. Isaacs and Mr. Green in this symposium will discuss in more detail about the use of foams and gels to improve the conformance.

To improve the rate of foam propagation, the pre-foam slug concept was extended to smaller slugs of low-interfacial tension (IFT) chemical, the use of solvents and the low-IFT injection of an air slug. The low-IFT slug was most effective in the hot-water portion of the steam flood while a solvent pre-foam slug was most effective in the steam zone. The use of air as a foam precursor proved very effective for near wellbore application. Figure 3 indicated the beneficial effect of the low IFT slug in the hot water zone.

Foam propagation experiments were carried out to determine the effects of frontal velocity, liquid volume fraction, steam flood residual oil saturation and surfactant concentration. It was shown that propagation was strongly dependent on velocity: strong mobility reduction occurred at low fluid velocity, with shear-thinning at high velocities. To provide a complete database for numerical modelling in conjunction with scaled-model requirements, the range of velocities was extended from a 0.3 to 300 m/day.

The flow of oil-in-water emulsion was studied at elevated temperatures in order to determine their effectiveness in controlling fluid mobility. The effect of droplet size on the ability of the emulsions to propagate through porous media was examined. Figure 4 depicts that when droplet size was sufficiently small, emulsions were able to travel

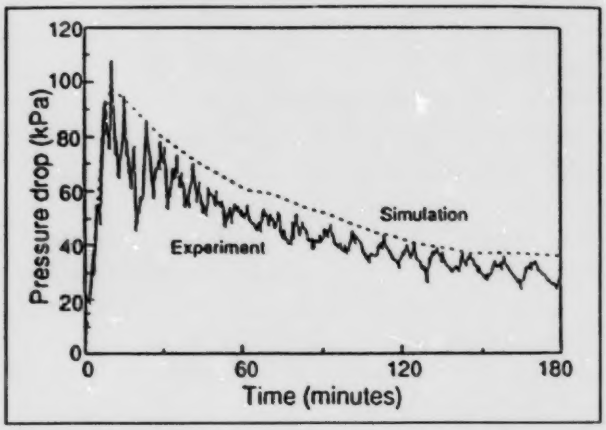

Figure 2. *Steamdrag experimental and simulated pressure-drop profiles show good agreement.*

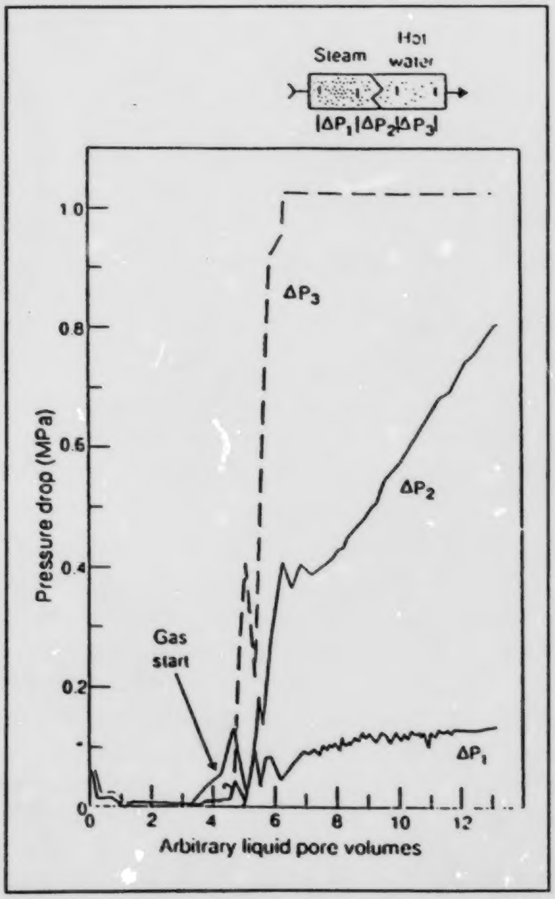

Figure 3. *Results of this steam run show the beneficial effect of the low-IFT slug (0.5 PV) in the hot water zone.*

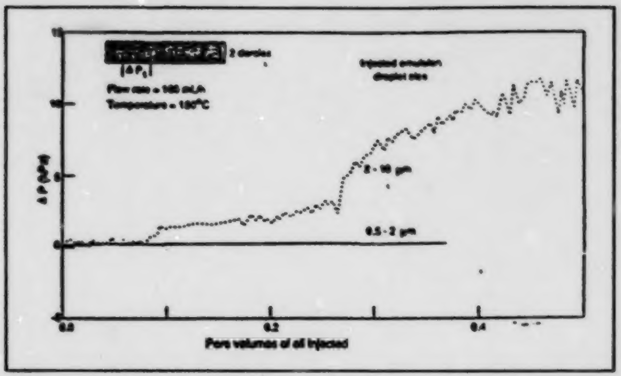

Figure 4. Below a certain droplet size, emulsions can pass through a sand pack with little or no plugging. Larger droplets are retained resulting in an increase in DP.

through a sand pack without droplet entrapment. This demonstrated that it is possible to produce emulsions which can propagate long distances into the reservoir.

Analysis of the flow behavior of foams, water-in-oil and oil-in-water emulsions and solvent-in-water dispersions provided a unified approach for understanding the flow behavior and potential application of these dispersions to improve reservoir performance. Regimes which favor the formation of stable dispersions were identified along with conditions for the propagation of the dispersions in porous media.

Advanced Process Development

In order to develop improved recovery techniques which are viable for the less productive reservoirs, the effects of their heterogeneous features and of process dynamics (e.g. steam quality, injection rates) must be understood and quantified. Furthermore, as has been demonstrated in a laboratory, improved bitumen recovery may be possible by using additives with steam. The objective of this project is to identify novel process concepts and production strategies that show promise of improving current recovery procedures.

Steam and steam-gas injection experiments for the recovery of bitumen from a Cold Lake reservoir with a communicating bottom water zone were conducted in a thermal high-pressure scaled physical model representing one-eighth of a five-spot pattern. It was found that the steam injection process was viable during the intermediate stage of the flooding but during the early stage suffered from delayed hot communications between the injection and production wells and a low oil-to-steam ratio. To improve the early performance of the process, flue gas was used as a steam additive. It showed promise in accelerating hot communications (Figure 5).

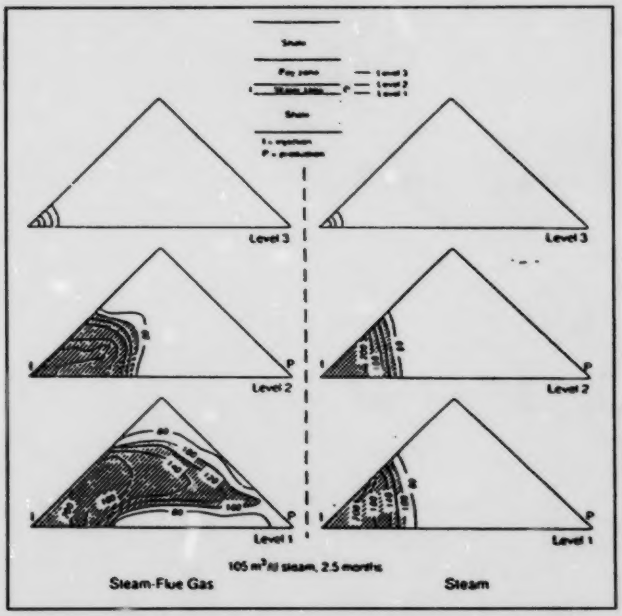

Figure 5. This illustration shows the flue gas channelling through the bottom water zone to the production well, thereby accelerating the hot communications between the wells.

The effect of reservoir parameters, such as bottom water to oil sands permeability ratio, on the performance of the process was also investigated. The results indicated that the permeability of the bottom water zone has a major impact on its performance. In a high permeability bottom water zone, the steam injection process performed poorly due to steam channeling to the production well, and resulted in less efficient heating of the reservoir.

Core experiments were carried out to investigate the effect of a number of variables on the steam-air process. The experimental results showed that, for steam diversion to occur, the temperature should be maintained at 200°C or lower. They also

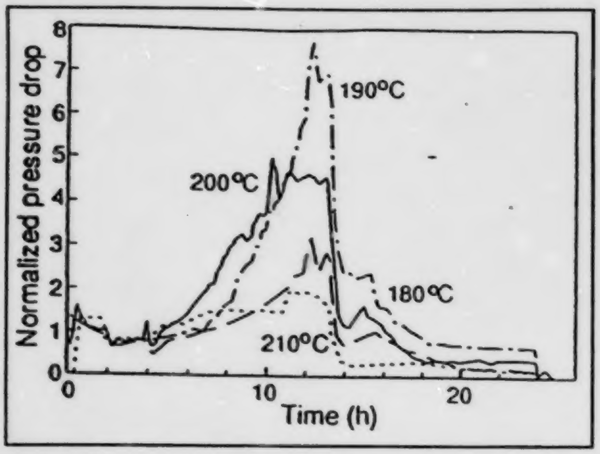

Figure 6. *The effect of air injection on pressure drop is highly dependent on temperature.*

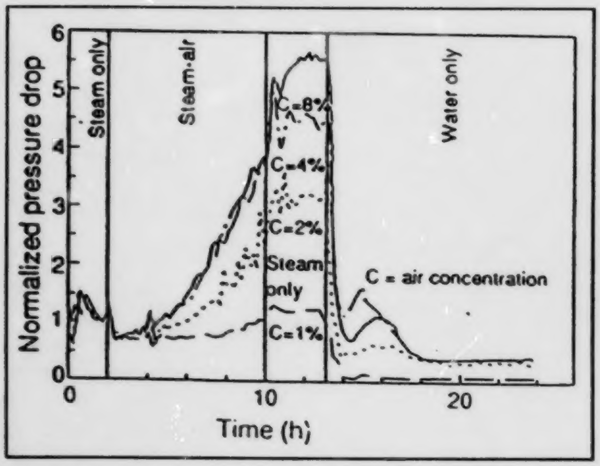

Figure 7. *The impact of air injection is dependent on the air concentration in the injection fluid.*

demonstrated that effectiveness of air as a diversion agent is dependent upon the air concentration in the injection fluid. Both results are depicted in Figure 6 and Figure 7, respectively.

In a three-dimensional steam-air run, air injection was started when the recovery rate has started to decline during steam-only injection. The result was a rapid but temporary increase in the bitumen recovery rate and slower but long-lasting increase in pressure drop (Figure 8). In a field situation, the latter effect would result in steam diversion.

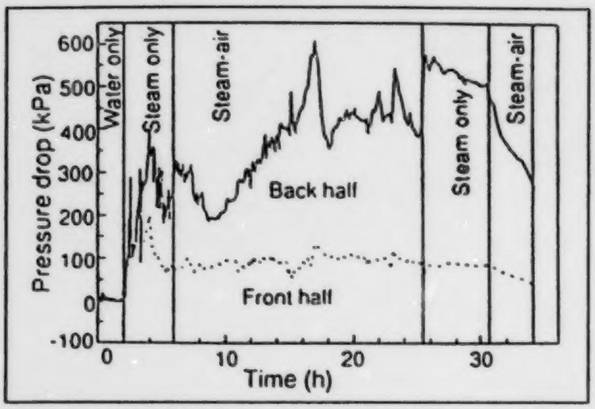

Figure 8. *In a three-dimensional steam-air run, air injection resulted in steam diversion, as demonstrated by an increased pressure drop over the back half of the communication path.*

Near Well and Production Related Studies

Most injection and production related problems in reservoirs occur in the near well region. The objective of this project is to characterize the chemical and physical phenomena in this region, to evaluate the effects of mineral reaction, scale formation, fines transport, sand production, wettability and corrosion on bitumen production, and to develop practical solutions to problems in the near-well area.

Carbonate zones in Alberta's oil sand reservoirs form barriers to steam. However, the stability of these barriers may be reduced by chemical erosion as a result of prolonged steaming. A series of autoclave and coreflood experiments showed that the chemical stability of the barrier is related to the clay type in the adjacent oil sands. The reaction of acid clays to form smectite and/or zeolite produces acid which attacks the carbonate barrier and breaks down the calcite to release Ca^{++} and CO_2. As shown in Figure 9, the most acidic clay, kaolinite, was the most distinctive.

Silica geothermometers was extended to the Alberta oil sand reservoirs. The temperature is estimated from the concentration of dissolved silica in the produced water and a knowledge of the silica phase or phases present in the reservoir which control the amount of silica released. Laboratory calibrations of the silica geothermometers under thermal recovery

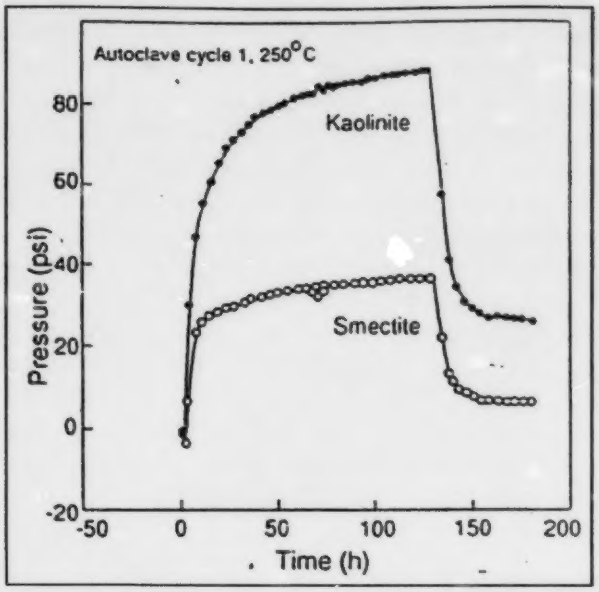

Figure 9. Reaction of carbonate barrier with kaolinitic- and smectitic-oil sand. Pressure plotted is CO_2 pressure due to the breakdown of the carbonate barrier.

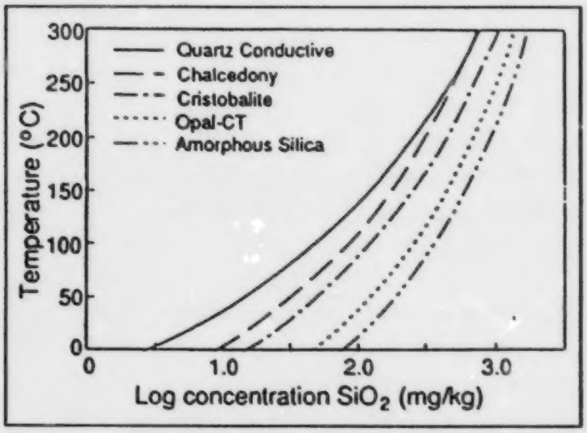

Figure 10. Silica geothermometer.

conditions with steam were made for all the major oil sand deposits in Alberta. In all cases, the appropriate silica geothermometer calibration result was found to lie between those of the quartz and chalcedony thermometers (Figure 10). These calibrations can be combined with the produced water chemistry in cyclic steam operations to monitor process temperatures in the near-well region.

Wettability is a major factor controlling the flow of fluids in a reservoir. It is affected by the interaction of oil and water with mineral surfaces and is independent on the hydrodynamic conditions present in reservoir. A novel method for measuring the wettability of dispersed sand in a flow field using an electroacoustical technique was developed and is currently under review for a patent protection.

Equilibrium Relationships and Transport Phenomena

Accurate and reliable equations are required to calculate the PVT and transport properties of bituminous fluid under recovery conditions for use in the reservoir simulators. The present database for bitumen-gas-water systems at elevated temperatures is sparse and the theoretical framework for representing these properties must be extended because of the complex nature of the fluids in question. The purpose of this project is to establish an adequate database at least for the major Alberta oil sands and heavy oil deposits and to select a suitable equation of state with modification for representing the phase behavior of the reservoir fluids under the in situ conditions.

The database of phase behavior for Athabasca, Cold Lake and Peace River bitumens with different gases are being established. Two equations of state, the Peng-Robinson and the modified Soave-Redlich-Kwong equations were selected to correlate the data obtained from this laboratory. A set of binary interaction coefficients and pseudo-critical parameters for different bitumens were recommended for use in the prediction of phase behavior under different conditions other than those that were experimentally investigated. Figure 11 shows, as an example, typical phase diagram obtained for Athabasca bitumen-methane-carbon dioxide at 343 K.

AOSTRA/ARC/INDUSTRY ACCESS PROGRAM

The Industrial Access Membership Program provides participating companies with direct access to research results, commercial use rights of project technology, and the opportunity to play a major role in developing the research program.

Long range planning for the program will be the responsibility of the newly established Policy and

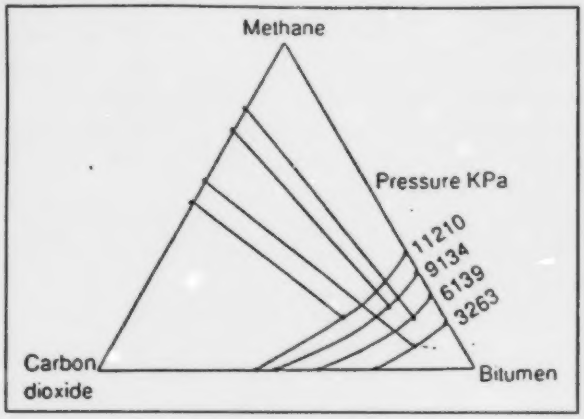

Figure 11. Equilibirum properties for Athabasca bitumen-methane-carbon-dioxide at 343 K.

Program Committee. The chief executive officers of both AOSTRA and ARC serve on this committee, along with senior executives from the Access Member companies.

The technical progress of the program is monitored by a Technical Committee, that is composed of Access Member representatives and the AOSTRA and ARC Program Managers. Committee Members work with the project leaders in developing the annual research plan, which is submitted in February for approval by AOSTRA and ARC.

Interactions at the working level are provided by project subcommittees, which include research or engineering staff from each Access Member company, AOSTRA and ARC. The subcommittees meet quarterly to review progress and develop research directions and priorities. The project subcommittees have emerged as a dynamic forum for exchanging ideas and identifying innovative project directions. It is very important that the research results for the AOSTRA/ARC/Industry Research Program yield new information or technology that will have significant, identifiable impact on field operations. More than 40 industrial representatives serve on the various project subcommittees that help researchers identify high priority areas of their work. Currently, the Industrial Access membership includes eleven companies or organizations, with the decision by Petroleum Recovery Institute and Energy, Mines and Resources Canada to join the program. This is the final year in the current five-year program. The Policy and Program Committee has directed the Technical Committee to develop a new five-year research plan with the emphasis on improved recovery and economics. In particular, 25 to 50% effort should be allocated to develop "high risk, high payoff" processes with the potential of producing bitumen and heavy oil at a significantly reduced cost by the year 2000.

CONCLUSION

The AOSTRA/ARC Industry Research Program is one of the major cost share of research and development programs which would directly benefit the petroleum industry. It is the primary vehicle for industrial input, both financially and technically, to AOSTRA's Institutional Research Programs and for technology transfer between public research institutions and the industry. This two-way transfer of technology and information has made this program unique and useful. The program is a role model of a government and industry partnership which combines their efforts to maintain research and to preserve the technology and expertise developed.

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AOSTRA UNIVERSITY RESEARCH INDUSTRY ACCESS PROGRAM

Ted Cyr
Alberta Oil Sands Technology and Research Authority

The University/Industry ACCESS Program is the primary means for broad-based industrial input to AOSTRA's University Research Program and for technology transfer from university researchers to industry. Eighteen companies have purchased membership in the program to obtain use rights or, as does CNPC, to observe the technology developed by AOSTRA-sponsored university research. These companies have the privilege of visiting university laboratories and interacting with the professors and their students. The highlight of the program is a two-day meeting in October of each year. There, the professors describe progress on their research.

The budget for the current program amounts to $2.5 million/year. Currently, the program supports 39 projects, each of one-, two- or three-years duration beginning July 1. In each calendar year and at the meeting in October, CNPC and the other companies receive results from about 55 completed, current or new projects. A brief summary of these results will be presented at this 2nd Canada-China Heavy Oil Symposium. This summary will be given in four parts: geophysics and geotechnics, upgrading and separation processes, in-situ processes, and physical and chemical properties of bitumen fluids.

INTRODUCTION

In 1974 when the Province of Alberta formed the Alberta Oil Sands Technology and Research Authority (AOSTRA), it was recognized even at that time that Alberta's oil sands could eventually become the most important resource for this province.

The resource, composed of mineable and more deeply buried deposits of bituminous sand, is present in sufficient quantity to provide paving for a four-lane highway encircling the world some 8000 times. Even the most conservative estimates had indicated that the resource was nearly the largest in the world. Unfortunately, little was known about this vast reservoir of hydrocarbons except that the reservoir was colder and therefore definitely more costly to develop than other resources.

Strip mining of shallow portions of the Athabasca deposit, as practiced by the Great Canadian Oil Sands Company (now Suncor Canada Ltd.) was economically feasible but this method was applicable to only about 10% of that deposit. Moreover, steam injection technology, as practiced in California and Venezuela, proved to be uneconomical, and gave disappointing results. Clearly, the skills or technology needed to profitably develop the other 90% of the deposit were untested or did not yet exist.

Some testing was being done but with each decrease in the price of oil, the testing would stop and the experts would leave. With another rise in oil prices, testing would start up once more and with it the learning process. New experts would have to be imported or trained and many of the earlier mistakes would be repeated.

This was a painfully slow and haphazard process which did not meet Alberta's economic imperatives. The province's economy was based to a major extent on the production of light oil, a production that would decline predictably by a factor of about two every seven years. Such were the principal factors which led to the formation of AOSTRA.

One of the first actions of the newly formed AOSTRA was to respond to serious concerns about the shortage of technical manpower and the need for specialized training facilities. Here it was recognized that many of the best minds in our nation were those of the professors at our universities. But they had to be persuaded to re-orient their research interests along lines relevant to Alberta's needs and to teach the needed technical skills to our students. This was an extremely complex undertaking, and AOSTRA is very proud of the success that has been achieved.

The sobering reality in 1974 was that only about 10 professors and as many students were doing relevant research on the oil sands and little was being taught about this major field of knowledge. Now, more than 80 professors, all first-class researchers in science and engineering, are teaching and doing advanced research of direct relevance to Alberta's great resource. Their laboratories are the best equipped in the world for this type of specialized investigation and their research reputations attract the finest students from Alberta and around the world.

More than 500 students have developed the needed special skills and obtained advanced degrees in the broad field of oil sands engineering and science. Most are working in Alberta's oil industry. Some are teaching. Their professors consult actively with their new colleagues in this important industry. This is how a technology-based society develops.

The professors and their students have achieved international recognition for the high quality and originality of their work. They have published the results of their research in internationally recognized scientific journals and account for more than 90% of such publications on Alberta's oil sands. They have formed their own companies to provide a much needed advisory service to industry and this influence is spreading internationally.

Universities provide a special environment for doing the experiments that test "radical" or innovative concepts. Evidence for this lies in the observation that most of Canada's patents and processes are based on research that began in universities. This is probably a direct result of emphasis on creativity in universities and the availability of graduate students seeking advanced degrees. Such challenges hone the professors' skills to cut through the most difficult problems and quickly find useful solutions. In this effort they are soon matched by their students. With financial and expert support from industry, AOSTRA allocates about one twentieth of its budget for funding research at universities in Alberta and the other provinces of Canada. Professors propose their best ideas for research. An independent panel of peers evaluates these proposals and AOSTRA allocates funds to those most highly ranked. The peers are all recognized leaders in research from universities and from industry.

The projects are of one-, two- or three-years duration. Professors periodically report the progress in their research and assign ownership of their technology to AOSTRA. At the Technical Review Meeting and Seminar held each year in October, the professors and their students present the current results of their research. This year, 250 senior scientists and engineers from the oil industry, universities and government attended the meeting to learn about progress on some 62 oil sands research projects.

This report outlines briefly some of the many highly creative accomplishments of university research teams of professors and their students and describe how governmental agencies and industries may join the AOSTRA/Industry/University ACCESS program.

HIGHLIGHTS OF RESEARCH

The budget in 1990/1991 for support of this research in Canadian universities amounted to approximately $2.5 million. Total funds expended in the previous 15 years amounts to $31,198,440.

The highlights listed below describe projects that were reviewed at the Technical Review Meeting and Seminar held this year September 30 to October 2 at the Banff Centre in Alberta. The highlights are given in four parts: geophysics and geotechnics, upgrading and separation processes, in-situ processes, and physical and chemical properties of bitumen fluids.

Geophysics and Geotechnics

Dr. M.B. Dusseault of the University of Waterloo completed a project to measure and model the volume and permeability changes that occur under the low shear-stress conditions that accompany high-pressure injection of steam and other fluids during in-situ recovery. He is completing another project to obtain geotechnical data needed to assess novel technological approaches to management of mine wastes deposited as overburden and tailings ponds. With Dr. L. Rothenburg, he began a new project studying the mechanics of the interactions of small particles of sand or clay and relating such to modeling processes of hydraulic fracturing and sand production. Dr. Dusseault is well known for his studies showing that dredging of clayey overburden may be best accomplished using saline or clayey tailings and for his studies showing how recovery processes in a reservoir divert subsequent fractures. Funding of this project and previous ones since 1977 amounts to $792,477.

Drs. E. Kanasewich and E. Nyland of the University of Alberta are developing novel methods for active and passive seismic tomography of an oil sands deposit that is being subjected to thermal recovery processes. They completed development and testing of computer algorithms that interpret signals received by geophones monitoring microseisms produced by an in situ process. The algorithm determines the distance and direction of the sources of the microseisms relative to the locations of the geophones. New work has begun to develop 2 1/2 and 3-D seismic migration before stack algorithms for improved imaging of steam zones and to develop effective methods for determining fluid content in sand reservoirs with amplitude versus offset analysis of reflected seismic energy. These results are directly relevant to reservoirs providing high velocity gradients and low quality factors such as those undergoing thermal recovery processes. Total funding of $1,225,872 has been allocated for this and earlier work over an eight-year period.

Dr. H. Machel of the University of Alberta is doing petrographic and geochemical studies of carbonate rocks and connate fluids obtained from the Grosmont and Hondo formations to identify and determine the effects of the major diagenetic processes. This work is in direct support of field-pilot tests of steaming of the Grosmont formation. The cost of this four-year project is $232,000.

Drs. N.R. Morgenstern and J.D. Scott of the University of Alberta are measuring the strength, deformability and permeability of oil sands that are being subjected to the high temperatures and pressures obtained in in-situ steaming processes. One of the geomechanical models developed in this project is the world's largest of its kind and is being used to predict the safety and performance of tunnels in the Underground Test Facility near Fort McMurray. Funds for this project and previous related ones over a ten-year period amount to $1,064,209.

Dr. S.G. Pemberton of the University of Alberta is investigating the regional stratigraphy and depositional history of the Grand Rapids Formation in the Athabasca, Wabasca and Cold Lake deposits. Traces of fossil workings and of other biogenic structures and of fossils provide good paleontological control of facies. These studies of data from more than 60,000 wells provide good regional predictive capability. Funds for these projects and previous related ones are $766,265 over 9 years.

Drs. J.S. Rogers and F.W. Jones of the University of Alberta are completing studies of short- and long-term tilt of the ground at an oil-sands steaming pilot, the AOSTRA/AMOCO GLISP site. Data from novel tiltmeters showing tilts of the order one ten-millionth of a degree are correlated with records of fluid flows. A numerical model is used to simulate the data. The cost of this eight-year project is $382,345.

Dr. D.R. Schmitt of the University of Alberta has developed an ultrasonic device that may be lowered in a wellbore to measure deformations of and near the wellbore and to observe fluid breakout. Results of observations are used to determine in-situ horizontal stress directions as a function of time and while nearby wells are being steamed. Funds for this three-year project are $228,684.

Dr. N.C. Wardlaw of the University of Calgary is doing microscopic studies of sandstones and carbonates obtained from Alberta reservoirs to determine the effect of factors such as wettability and pore geometry on fundamental processes important to enhanced recovery of bitumen and heavy oil. Funds for this project and earlier ones amount to $537,384 over six years.

In Situ Processes

Dr. A.K. Ambastha of the University of Alberta is determining the applicability of pressure-falloff tests to determine the size of the steam chamber and other parameters that affect the performance of the steaming processes for recovery of bitumen and heavy oil. Data from field tests and from numerical models of fractured wells, horizontal wells, composite reservoirs, etc. will be analyzed. Funds for this three-year project amount to $173,460.

Dr. R.M. Butler of the University of Calgary is doing theoretical- and physical-model studies of the steam-assisted gravity-drainage process for the recovery of heavy oils and bitumen. Prior to joining the University of Calgary, Dr. Butler was for many years manager of heavy-oil research for Imperial Oil. He is responsible for Imperial's first field-scale pilot tests of horizontal wells. Now, his concepts are being field-pilot tested at AOSTRA's Underground Test Facility near Fort McMurray. Funding of this three year project is $330,000. Funding of previous ones amounts to $912,500.

Drs. F.S. Chute and F.E. Vermeulen of the University of Alberta have been measuring electrical properties of oil sands, developing physical models of electrical heating processes, and evaluating the use of electrical power for selective heating of oil sands. This work is the subject of a patenting effort assigned to AOSTRA. Funding of this three-year project is $300,000 and for previous ones since 1978 is $567,633.

Dr. D.E. Cormack of the University of Toronto is developing a three-dimensional numerical simulator for application to the steam-assisted horizontal-well gravity-drainage process. An unique feature of this simulator is that it employs a "deformable moving grid." Also he is investigating the effects of non-condensable gases on the development of steam chambers. Funding of his current two-year project and earlier studies amounts to $215,310.

Dr. J.W. Costerton of the University of Calgary is investigating the use of bacteria to selectively plug high permeability zones in a reservoir and thereby improve conformance of waterfloods and inhibit coning. The fundamental concept is that dormant bacteria are easily injected into a reservoir but active bacteria are not. Dormant bacteria may be mixed with appropriate nutrient to grow after a long period of induction at great depths in the reservoir. This is particularly useful if the mixture is injected as a waterflood nears completion. The results of this work are described in a patent assigned to AOSTRA. A total of $797,000 has been allotted to this and earlier projects over eight years.

Dr. F.A.L. Dullien of the University of Waterloo is doing laboratory studies to study a novel process using gas to displace residual oil from samples of oil-sands core that have been waterflooded. An x-ray CAT scanner is used to determine production history, saturations and relative permeabilities of small elements of these heterogeneous cores. Dr. Dullien is well known for his simple laboratory demonstration of a waterflood where oil and water flow in opposite directions! Funds for this three-year project amount to $239,160.

Dr. S.M. Farouq Ali of the University of Alberta is studying the use of small amounts of carbon dioxide gas to improve the commonly-used water-flooding process for recovery of Alberta's light oils, developing new methods of control of mobility to improve recovery of heavy oil or bitumen from the Athabasca and Lloydminster deposits and improving a computer program that models oil recovery and fracturing of oil-sands formations during injection of steam. Funding of these projects amounts to $1,871,068 over ten years.

Dr. R.E. Hayes of the University of Alberta is doing laboratory experiments to determine the propagation of ionic and non-ionic surfactants in cores providing simultaneous dispersion and adsorption. A finite-element numerical model is being developed. It is based on the Navier-Stokes equations. The cost of this two-year project is $58,232.

Drs. D.W. Bennion and R.G. Moore of the University of Calgary are continuing their investigation of mechanisms of dry- and wet-in situ combustion in oil sands and the low temperature oxidation of bitumen. Their previous work provided much of the fundamental concepts that lead to field-scale pilot testing of a process whereby oxygen is injected into a steamed reservoir to enhance production of bitumen. Funding for this project amounts to $325,000. Total funding for this project and ones done over the past thirteen years is $2,293,764.

Dr. W.G. Laidlaw of the University of Calgary is developing a numerical model based on network theory to characterize the flow of foam through and oil-sands formation. Funds for this three-year project amount to $135,000.

Dr. J.A. Rogers of the University of Alberta is developing microencapsulation techniques to transport bacterial nutrients into a reservoir. Microcapsules of diameter less than one micron can be placed at depth in a reservoir to release contents over at least a 30 day period. This three-year project is related to one described earlier for Dr. Costerton and costs $262,750.

Drs. J.D. Scott and N. Kerr and Ms. E.A. Richards of the University of Alberta completed designs and fabrication of prototypes of geotextile filters to be used in conventional production of heavy oil. These filters provide low pressure drops and little plugging while screening sand from oil and water flowing into a well. Funds for this project and an earlier one amount to $129,566 over three years.

Dr. T.J.T. Spanos of the University of Alberta is developing fundamental mathematical expressions and algorithms for numerical simulation that describe flow of mixtures of bitumen, water and gas in heavy-oil reservoirs. The expressions are consistent with the Navier-Stokes relations and describe non-Darcy flow and viscous fingering. Also, expressions have been developed to describe the slow propagation of seismic waves through an oil-sands deposit. Now, these expressions are being incorporated into numerical models. The cost of this project and earlier ones amounts to $452,973 over eight years.

Dr. H. Vaziri of the Technical University of Nova Scotia is improving a numerical model, ENHANS, to simulate thermal processes for recovery of bitumen. The unique features of the improvements are that it is a thermo-mechanical one that accounts for multiphase flow of fluids and suspended solids and deformation of the sand matrix. The model may be applied to well-bore instability, fracturing of the reservoir and sand/oil production. One important conclusion is that for certain deposits, optimal production of heavy oil is obtained with production of sand. The cost of this project and an earlier related one is $164,760 over five years.

Upgrading and Separation Processes

Dr. M.C. Baird of Queen's University is developing water-soluble catalysts whose aqueous solutions dispersed finely in bitumen will catalyze the hydrogenation of unsaturated linkages of bitumens at temperatures much lower than those of conventional processes. This project has been funded at $80,000 over two years.

Drs. L.A. Behie and W.Y. Svrcek of the University of Calgary are generating basic kinetic data for ultrapyrolysis of Alberta heavy oil using a novel micro-reactor system and determining product distribution. Heating rates of the bitumen much in excess of 1000 C/second are achieved in this reactor. Funding of this work amounts to $203,000 over three years.

Drs. P.M. Boorman, R.A. Kydd and T.S. Sorensen of the University of Calgary are developing hydrocracking catalysts capable of being used under relatively mild temperature conditions to enhance the yield of liquid products with low aromaticity. Funding of this project amounts to $198,682 over four years. Total funding of this project and previous ones done since 1976 by Dr. Boorman amounts to $698,713.

Dr. N.O. Egiebor of the University of Alberta is doing bench-scale pilot tests to determine the technical and economic feasibility of a novel process for combustion of coke. Coke is coagglomerated with a specially prepared silica sorbent to make a smokeless solid fuel that provides much reduced emissions of sulfur dioxide. This work is the subject of a patenting effort. Funds for this one-year project amount to $62,000.

Dr. M.R. Gray of the University of Alberta continues to develop methods to characterize heavy oils, bitumens and other feedstocks in terms of functional groups and other chemical moieties and how such affect the kinetics of refining of these feedstocks. Funding of this three-year project, and an earlier one with Dr. I.G. Dalla Lana amounts to $479,000.

Dr. A. Jeje of the University of Calgary is studying fundamental mechanisms that affect the efficiency of the hot-water process used to extract bitumen from mined oil sands. The amount of funding for this two-year project and for an earlier one on in-situ oil recovery by injection of carbon dioxide gas is $118,520.

Dr. J. Masliyah of the University of Alberta completed studies of methods of cleaning the froth that is obtained by flotation of hot slurries of oil sands and water. He developed correlations showing optimal froth washing for a hot-water extraction process. Now, he is measuring the rheology of these slurries and those found in tailings ponds and in a separate project is developing a novel method using microwaves to demulsify water/oil emulsions. The cost of these projects amounts to $522,698 over ten years.

Dr. K. Muehlenbachs of the University of Alberta is measuring the concentrations of isotopes of hydrogen and carbon in current commercial and experimental processes for upgrading of bitumen. The data details the effects of certain catalysts on the "scrambling" of hydrogen and carbon moieties that occurs in these processes. The work is relevant to hydrocracking of mixtures of coal and bitumen. Funding for this three-year project amounts to $203,000.

Dr. E.L. Tollefson of the University of Calgary is completing bench-pilot scale experiments of a novel process to minimize bogging that can occur in a commercial fluidized-bed coker. Funds for this two-year project are $200,000. Funds for earlier work on desulphurization of coke and on sludge treatment are $578,370 over eight years.

Dr. J.K.S. Wan of Queen's University is completing bench-scale and large pilot experiments on a novel process that uses microwave heating of dilute catalysts to selectively hydrocrack volatile fractions of bitumen. Also, Dr. Wan is doing similar experiments to improve his patented process for generation of alpha-olefins from alkanes. This patent has been assigned to AOSTRA. Total funding of this and previous projects is $489,524 over eight years.

Physical and Chemical Properties of Bitumen Fluids

Dr. P.J. Crickmore of the University of Alberta is using fractal analysis to derive and suggest solution methods to the governing equations for flow of fluids in in-situ recovery processes. These governing equations may be written as fractional order differential equations of non-integral dimension and with memory. This method of analysis shows great promise for treating problems such as viscous fingering. Previously funded work on fractal dimensional analysis of well-logs from oil-bearing deposits showed common characteristics and suggested appropriate sampling frequencies for cores and logs. The cost of this project is $103,610 over three years.

Drs. P.M. Fedorak and D.W.S. Westlake of the University of Alberta are doing laboratory studies of the ability of certain micro-organisms to metabolize asphaltenes that are a major component of bitumen and heavy oil. Encouraging results are reported for ligninolytic fungi that use the chloroperoxidase enzyme to oxidize petroporphyrins attached to asphaltene. This 5-year project costs $316,250.

Dr. L.G. Hepler of the University of Alberta is investigating the kinetics and thermodynamics of oxidation of bitumen to obtain quantitative relationships useful in modeling in-situ recovery processes. Funding for this two-year project and earlier ones on colloids, sludge treating and gas dissolution in bitumen has amounted to $1,116,988 over twelve years.

Dr. I.E. Hutcheon of the University of Calgary is doing laboratory work and field studies to characterize the dissolution and precipitation of minerals in thermal processes for recovery of bitumen. This work is particularly relevant to reservoirs containing swelling clays or minerals that dissolve in one part of the reservoir and precipitate near producing wells. Funding of this eight-year project amounts to $800,350.

Drs. S. Levine and B.D. Bowen of the University of British Columbia are using theory and experiment to identify the mechanisms by which fine particles and clays stabilize the emulsions that are found in oilsands tailings ponds. Tailings ponds are costly and important to the environment. AOSTRA has encouraged new research in this area this year by holding workshops. Funds for this seven-year project amount to $432,416.

Dr. Y. Koga of the University of British Columbia is developing a method to characterize aqueous suspensions of 5 to 100 nanometer particles of clay. For a highly collimated beam of X-rays, analysis of the X-rays transmitted or reflected at very small angles provides the following information about the suspended particles or flocs: the average size, total surface area, total excluded volume and volume. The results are directly relevant to tailings ponds produced by the hot-water extraction process. Funds for this three-year project amount to $151,709.

Dr. F.J. Longstaffe is doing a detailed regional study of natural diagenesis in sands, sandstones and shales of the Clearwater Formation near Cold Lake, Alberta. Funds for this two-year project and an earlier related one amount to $324,967.

Dr. B.C.-Y Lu of the University of Ottawa is doing laboratory experiments to measure phase equilibria of mixtures of water and bitumen under conditions obtained in in-situ recovery processes. Funding for this project and an earlier one amounts to $286,460 over five years.

Dr. D.Y. Peng of the University of Saskatchewan is developing an equation of state that provides a thermodynamic description of continuous distribution of hydrocarbons found in bitumen/gas mixtures. Expressions are being derived that may be useful in simulation of in-situ recovery processes and of upgrading processes. Funds for this and two earlier projects amount to $312,556 over five years.

Dr. V.R. Puttagunta of Lakehead University completed work to develop a simple correlation to predict the viscosity of oil-diluent-gas mixtures over a wide range of pressures and temperatures. The oils selected from around the world include bitumen, heavy oil, thermally altered oils and residua, lubricant formulations and multicomponent liquids (emulsions). This four-year project costs $98,232.

Dr. O.P. Strausz of the University of Alberta is doing laboratory experiments to assess the use of superacids for commercial hydrocracking of bitumen and heavy oil. Also, he is developing new processes such as continuous steam-flow coking for upgrading of bitumen. Dr. Strausz is a signal researcher in the chemistry of bitumen and its many components and in the development of novel processes for extraction and upgrading of bitumen. Funds for these two projects is $400,000 over 4 1/2 years. Funds for previous projects on the chemistry of bitumen, causes of poor recovery of bitumen from some deposits and on soluble catalysts for hydrotreating amount to $3,180,184 over 12 years. Moreover, Dr. Strausz agreed to write an extensive monograph on the chemistry of bitumen. For this purpose, funds amounting to $100,000 have been allocated.

THE AOSTRA/UNIVERSITY/INDUSTRY ACCESS PROGRAM

The AOSTRA/University/Industry ACCESS Program is the primary vehicle for broad-based industrial input to the AOSTRA University Research Program and for technology transfer from university researchers to industry.

Under the terms of the ACCESS program, member companies purchase non-exclusive use rights to the technology developed by AOSTRA sponsored university research, and have the privilege of visiting university laboratories and interacting with the faculty and students. Results are presented at a two-day meeting in October of each year, and all reports and patents are conveniently monitored through a confidential database.

The three industrial members of the six-member University Research Evaluation Panel are selected from ACCESS member companies' staff. Professors submit their best ideas for research and this panel of peers ranks applications in order of technical merit and need. Funds are allocated to those applications ranked most highly.

ACCESS Membership is an important means of identifying key areas for research and of transferring new technology to industry. Also, it is an important sign of industrial confidence in the largest funding program in Canada for university-based research on heavy-oil and enhanced-oil recovery and processing.

Associate memberships provide ACCESS to the reports and to the Annual Technical Review Meeting and Seminar. They do not include technology use rights. While informal input to AOSTRA is actively encouraged, Associate Members do not regularly participate in formal evaluations of progress or proposals.

The cost of a Full Membership is $50,000 per calendar year and an Associate Membership is $10,000 per calendar year.,

In cases where both the university group and an ACCESS member wish to do so, the industrial company may become involved in a university project in a collaborative way. The nature of the collaboration is unique to each project and company, and takes the form of contributing research ideas, technical expertise, equipment, analytical resources, or access to field pilot facilities or data. AOSTRA's role is to encourage such collaboration. Benefits to the company include research directly relevant to the company's operations, and improved technology transfer as a result of increased involvement with the university community. AOSTRA encourages and actively assists this industry/university liaison.

CONCLUSION

AOSTRA's university research program is the largest of its kind supporting research on recovery of bitumen and heavy oil, on enhanced recovery oil and on processing of bitumen and oil. The program provides financial support for relevant research being done by Canada's brightest engineers and scientists working in a very special environment for doing experiments that test "radical" or innovative concepts. This program is important for generating much important research activity relevant to development of Alberta's oil sands, for inventions of novel processes, for generation of fundamental concepts and data, and for training of students.

In this paper a summary of the results of more than 60 research projects current in this calendar year and being done by 42 teams of professors and their students has been described briefly. This summary was be given in four parts: geophysics and geotechnics, upgrading and separation processes, in-situ processes, and physical and chemical properties of bitumen fluids. These projects are confidential and therefore the presentation was of a general nature.

In addition to supporting research projects relevant to the needs of oil producers and refiners the training of many students and specialists, the program also provides excellent transfer of new technology to industry. By joining AOSTRA's University/Industry ACCESS program, companies purchase non-exclusive use rights to the technology developed by the university research program and benefit from close interaction with professors and students research relevant to the companies' needs. Companies also receive copies of all reports and attend specialist workshops and the Annual Technical Review Meeting and Seminar held each October. Moreover, the professors and students benefit much from this interaction and receive much assistance from the companies. This assistance is in the form of advice, material and access to results of field-tests.

ANALYSIS OF RESULTS FOR RESERVOIR DESCRIPTION OF A HEAVY OIL RESERVOIR

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ABSTRACT

Jinglou anticlinal reservoir of the Henan oil field is a part of the west slope of the Miyang depression and is a composite heavy oil reservoir controlled by multiple factors, such as faulting, lithology, unconformity, etc.

In this study, six key wells, eight appraisal wells, six correlation profiles, four fence diagrams, and one synthetic seismogram were used for the overall description of the said reservoir.

The methodology of description is to send different information into data base by interactive dialog or in batch with the function of a large reservoir description software package (RDSP), and to obtain the final results by utilizing the function of expert systems and multi well evaluation subsystems.

In a study of the key wells, the analysis of the geological parameters, such as lithology, structure and sedimentary features as well as the distribution of reservoir fluids were emphasized.

The results of this study provide the characterization of this heavy oil reservoir. The conclusions especially include: a newly proposed well pattern, the hydrocarbon accumulation region, and the predicted highly productive area. These provide the basis for further exploration and development of this reservoir.

OBJECTIVE OF THIS STUDY

In the Jinglou anticlinal reservoir, there are 29 wells drilled to date, including six wells with cores and 13 wells used for steam stimulation. The well depth ranges 350 to 800 meters. The vertical profile of formation is characterized by a sedimentary assemblage of sand-conglomerate, and medium-to-fine sandstone with thin laminations of mudstone. The coarse texture and large variations in thickness exist in the sandstone.

The distribution of oil/gas/water in the reservoir is complicated by the geological conditions of structure, stratigraphy, lithology, and the petrophysical properties of reservoir rocks. Regarding oil production, the multi-layered lower Tertiary pay zones produced heavy oil with a low rate by thermal recovery.

Development of this kind of reservoir requires certain knowledge of the proven reserves, hydrocarbon accumulation, location of highly productive areas, and the selection of flood pattern for operation. The objective of this study is to answer these questions by using the data from the reservoir description that enables us to understand this reservoir and to have the information for rational reserves development.

DESCRIPTION TOOL — RESERVOIR DESCRIPTION SOFTWARE PACKAGE (RDSP)

For reservoir description, we developed the Reservoir Description Software Package (RDSP). It consists of seven subsystems as follows, and the RDSP structure is shown in Figure 1.

1. Pre-processing subsystem (PP)
2. Single well evaluation subsystem (SE)
3. Dipmeter processing subsystem (DIP)
4. Expert system (ES)

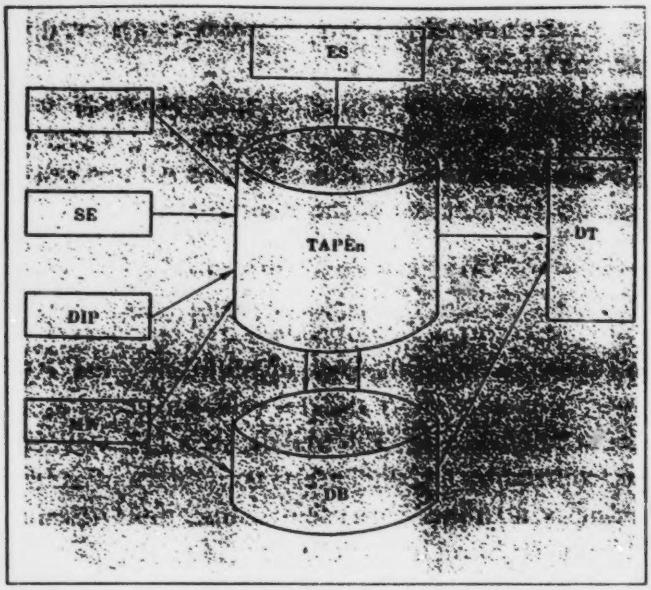

Figure 1. RDSP Structure

5. Data base subsystem (DB)
6. Multi well evaluation subsystem (MW)
7. Display technique subsystem (DT)

ANALYSIS OF THE RESULTS

Calculations of the Geological Parameters

Porosity. The core samples show that rock in the Jinglou reservoir vary greatly from loose to compact sandstone. For this study, the calculated porosity obtained from the model,[1,2] agrees fairly well with the measured data.

The average core-derived porosity O_{ca} is quite close to the average processed porosity O_{pa}. The average core porosity of 40 layers in this reservoir is: $O_{ca} = 33.56\%$, $O_{pa} = 30.96\%$, and the relative deviation is 7.7%.

The frequency distribution of core-derived porosity O_{ca} and processed porosity O_{pa} is very much alike, as shown in Figure 2.

The good linear relationship exists between O_p and O_c as shown in Figure 3, and in Equation (1).

(1) $O_C = -0.59 + 1.13 * O_p$

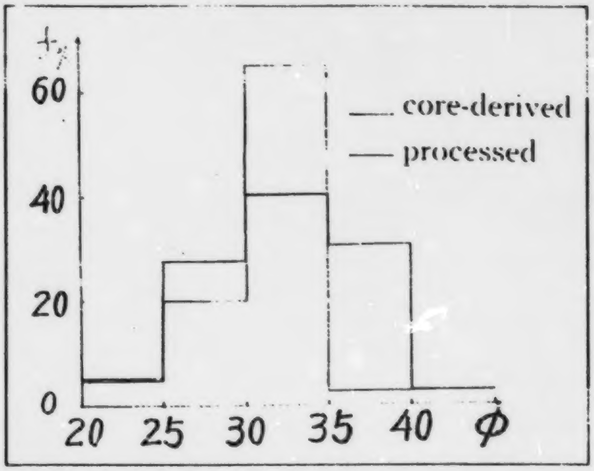

Figure 2. The frequency distribution of core-derived porosity ϕ_c and processed porosity ϕ_p.

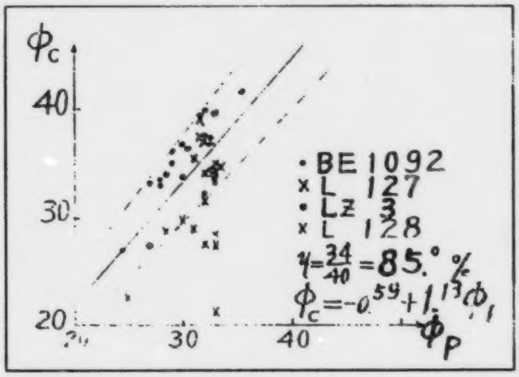

Figure 3. Relationship exists between ϕ_p and ϕ_c

The data of O_p and O_c are matched very well as shown in Figure 4. The values marked by "*" are core-derived porosities.

Oil saturation. From the analyses of oil-base cores and the carbon/oxygen logs, the oil saturation obtained by processing log data is quite reliable.

For the oil saturation greater than 50%, the average value of processed oil saturation ($S_{op} = 66.1\%$) and the average value of oil-based mud core data ($S_{ob} = 63.44\%$) are close to each other. The relative deviation of these is 4.19%. The average value of carbon/oxygen saturation is $S_{oc} = 65.9\%$, and the relative deviation is 0.3%.

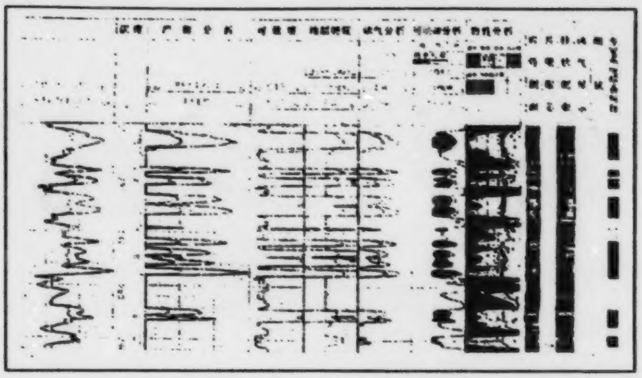

Figure 4. The discreet data of ϕ_p and ϕ_c.

The frequency distributions of S_{op}, S_{ob}, and S_{oc} are very much similar as shown in Figure 5. In which, the peak of these saturations exists in the interval of 60–70%, being 37.8%, 31.8%, and 27.8% respectively. This should not be regarded as an accidental coincidence but a reflection of reality.

The data of S_{op} and S_{ob} are matched fairly well as shown in Figure 6.

Sand thickness. The sand thickness obtained from reservoir description agrees well with the core-derived thickness.

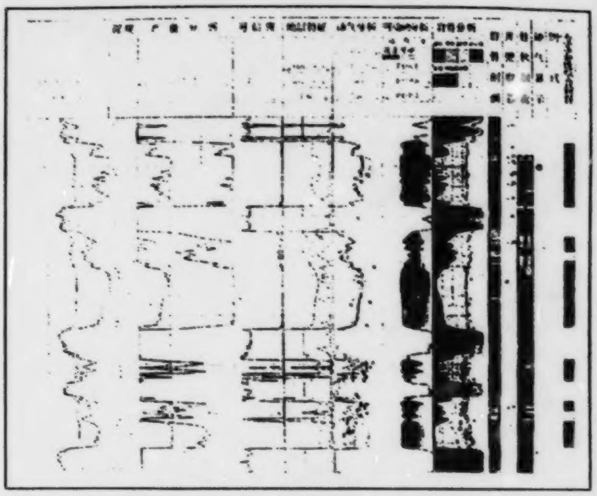

Figure 6. The discreet data of S_{op} and S_{ob}.

The processed sand thickness, h_p, and core-derived sand thickness, h_c, show an overall relative deviation of 6.7%.

The absolute deviation (ad) of h_p and h_c is relatively small. For example:

ad < 0.2 m 62.1% of samples

ad < 0.5 m 86.5% of samples

A good linear relationship exists between h_p and h_c (Figure 7) with a accuracy of 89.2%, i.e.,

$$h_c = -0.01 + 0.97 * hp \qquad (2)$$

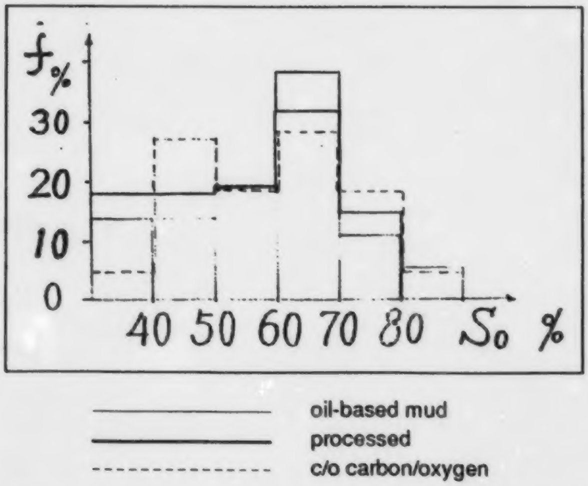

Figure 5. The frequency distribution of S_{op}, S_{ob}, and Soc.

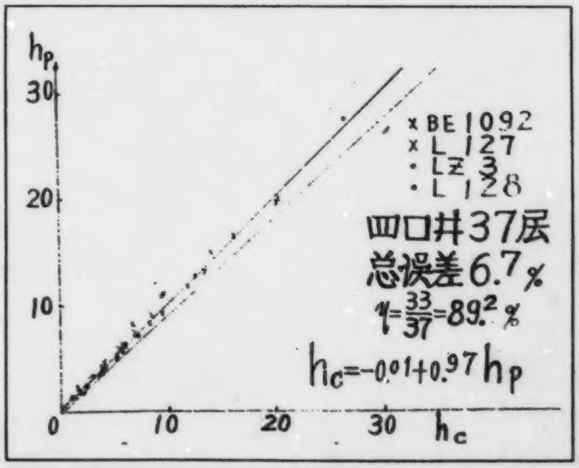

Figure 7. A good linear relationship exists between h_p and h_c.

Permeability. Previous studies[1,2] reported that the variation of permeability is in the range of 0.15–4.9 μm², averaging 1.7 μm². A statistical analysis of the data from 14 wells in the data base indicated a variation of 0.1–4.9 μm², the relative deviation being 14.1%.

Lithological Identification

Twelve types of lithology, such as conglomerate sandstone, conglomerate containing unevenly grained sandstone, medium to fine sandstone, argillaceous sandstone, siltstone, mudstone, argillaceous dolomite are identified in the description. In a comparison with core samples, (1,064.7 m from 6 wells), 81.45% of the cores were matched. The profiles of processed lithology,[5,7] from sidewall and conventional cores are shown in Figure 8.

Zone Identification

The parameters used for zone identification as listed in Table 1 were obtained by using three qualitative and thirteen quantitative approaches (references 3,4,6,8). As compared with the production test of well BE-1092, 75% of the tested zones agreed with the predictions of this study (see Figure 9).

Regional Geological Features

For this study, the pay zones are coded to facilitate processing, for example, the fourth sub-layer of the third group is coded 304, the sixth sub-layer of third group 306, the fifth sub-layer of the fourth group is coded 405, etc.

Depositional features. The litholigical profile in well L-127 is a sedimentary assemblage of conglomerate, medium-to-fine sandstone with thin laminations of mudstone, as shown in Figure 10.

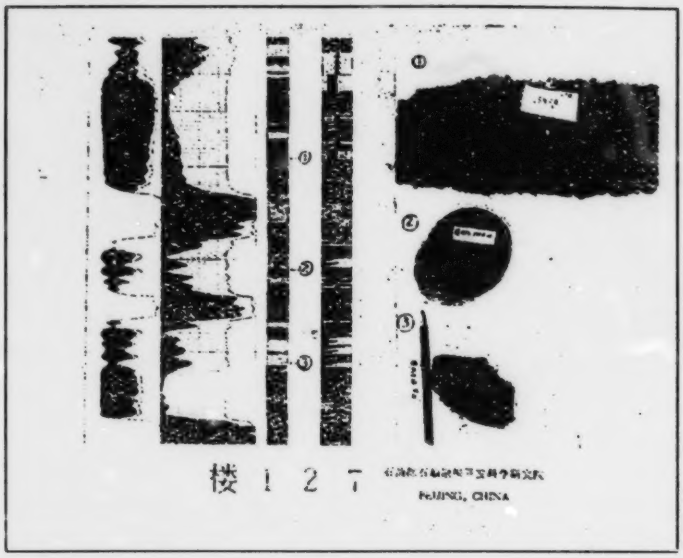

Figure 8.

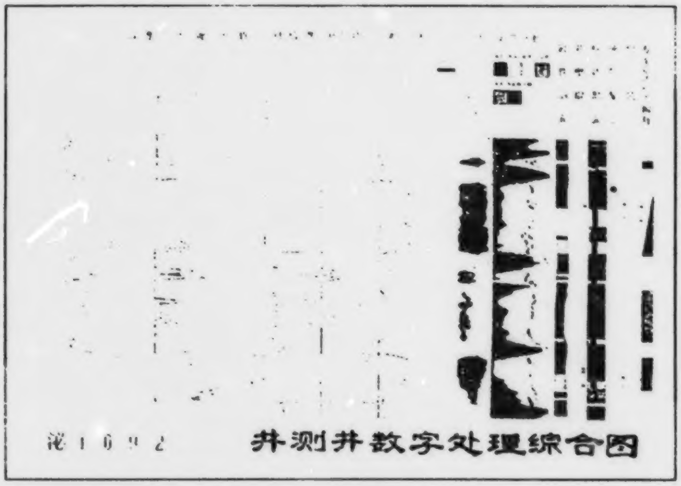

Figure 9.

Figure 11 shows the No. 6 profile in the southeastern part of the anticline, the lithology is characterized by coarse grain and thick sand bodies. While the thin sands with less coarse, more argillaceous sediments are observed towards the northwest. These type of changes are also presented in the well data shown in Table 2. For this reservoir, the coarse-grain texture, large variation of sand thickness, and corresponding changes in shale content demonstrate the sedimentary features of sub-aqueous deltaic channel facies.

Table 1. Parameters of identification

Zone/Parameter	P1	R_r/R_o	K_0	K	D_{hy}	Fw	ϕ	S_0	W_{pg}	S_{wm}	PP	C_{11}	C_{12}	C_{13}	R_{ES}
Oil + Gas	≥0	>2.85	>0.7	≥0.1	>0.6	≤40	≥20	>46	0–0.5	<22	>0.04	>80			OG
Gas	≥0	2.85	>0.7	≥0.1	0.5–0.6	≤40	≥20	>46	≥0.5	<22	>0.04	>80			G
Oil-water coexisting	≥0	1.8–2.85	0.2–0.7			40–80	≥20	30–46		22–40			>75		OW
Water	≥0	~1	<0.2	≥0.1		≥80	≥20	<30		>40	≤0.001			>75	W
Dry	<0	~1	~0.001	<0.1		~0	<20	<20	~0	~0	≤0.001				D

Table 2. Variation of sand thickness and shale content

Layer	Direction	Southeast ——▶ Northwest							
	Well number	B108	1525	1925	1921	L127	BE1092	LZ3	LQ8
306	Thickness h	21.5	15.21	20.0	19.63	19.63	8.25	9.0	13.63
	Shale content V_{sh}	11.63	2.75	4.18	6.62	21.04	10.44	9.36	19.95
306	Thickness h		3.5	9.5	7.0	3.25	11.25	1.12	2.87
	Shale content V_{sh}		8.08	10.04	9.02	29.97	2.62	25.86	23.23

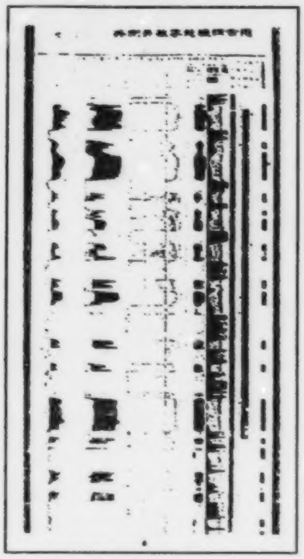

Figure 10.

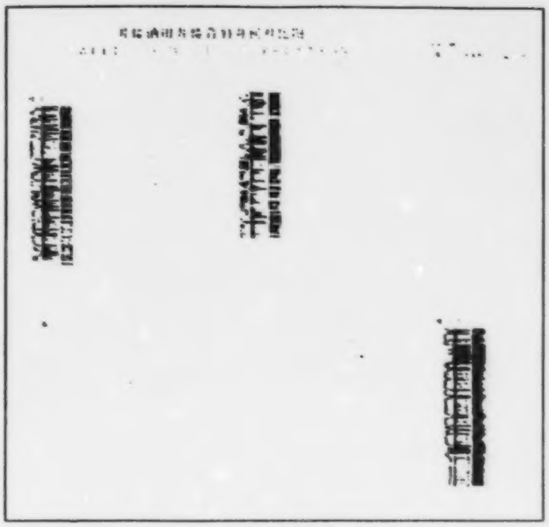

Figure 11.

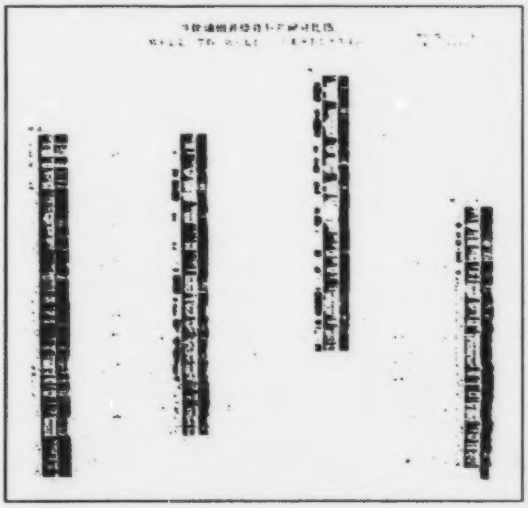

Figure 12.

The texture changes from coarse to fine grains are indicated on profile No. 5 across the anticline from east to west (Figure 12). It is apparent from Figure 11 and Figure 12 that sediment sources were from the southeast of the anticline. We therefore infer that the direction of an ancient river channel coincides with the southeast-northwest axial direction of the present anticline, as shown in Figure 13.

Structural features. Figures 11 and 12 show a structural high near Well L-127. The seismic profiles 406, 299.5 (Figures 14, 17) display a gentle sloping structure with little undulation. The synthetic seismogram, based on line 406 (Figure 16), shows both structure configuration and good formation communication. These conclusions have been verified by geological, drilling, seismic and logging data.

Reservoir fluids distribution. Oil and gas accumulation can be found at the structure high, i.e., the area of Wells L-127 and 1921, where the thick intervals encounter a number of oil-bearing zones. On the contrary, the structure's low area turned out to be water-bearing zones, as shown Figure 17.

The highly productive region with Wells L-127, 1921, and 1721 can provide a maximum daily oil rate of 0.5 t per well as shown in Figure 18.

In the eastern part of the anticline with Wells L-128, B-108, and the east of them is a promising region with the layer 305 covering the area of about 0.51 km^2 (Figure 19).

In the northwest-southeast axial direction from Well BE-1092 to LZ-3 is also a promising region with the layer 306 covering the area of about 0.44 km^2 (Figure 20).

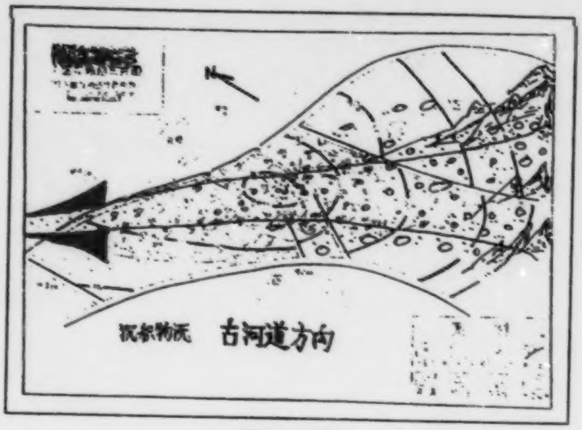

Figure 13.

南阳油田井楼背斜测井地震综合图
WELL-TO-WELL CORRELATION
N

Figure 16.

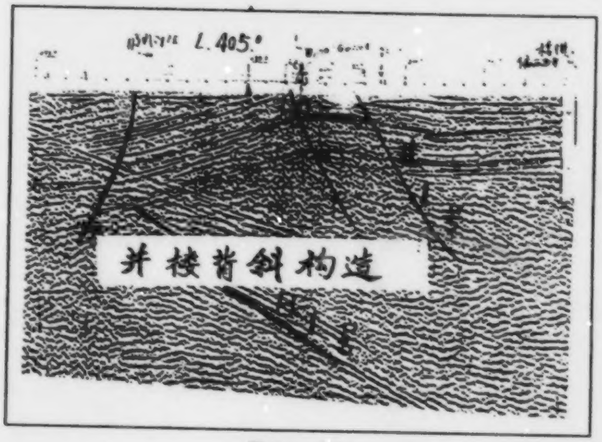
L.405.°
井楼背斜构造

Figure 14.

Figure 17.

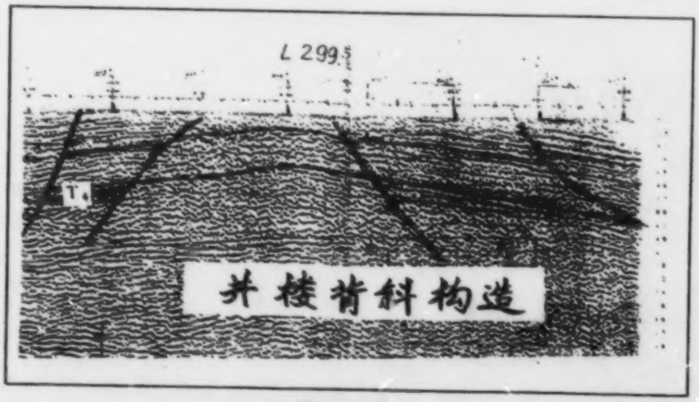
L 299.5
T4
井楼背斜构造

Figure 15.

The fence diagram in Figure 21 shows good formation communication, especially in the major pay zones in the highly productive areas.

In the eastern part of the anticline, there is no need to drill wells to the depth below layer 306. Also in the northwestern part, no well is required to be drilled below layer 307. This means that a total footage of 12,000 m and 6,000 m can be saved in the above regions respectively.

A revised well pattern recommended for field practice is shown in Figure 22.

井楼构 三段Ⅲ6等产能图

Figure 18.

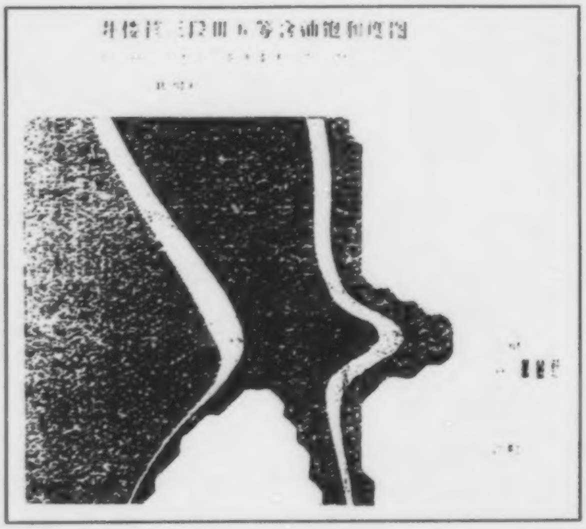

Figure 20.

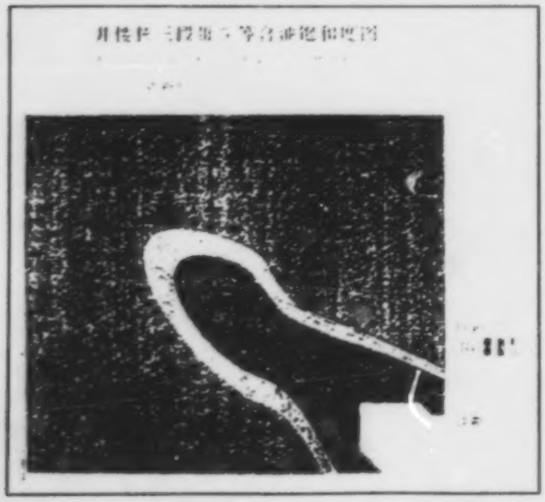

Figure 19.

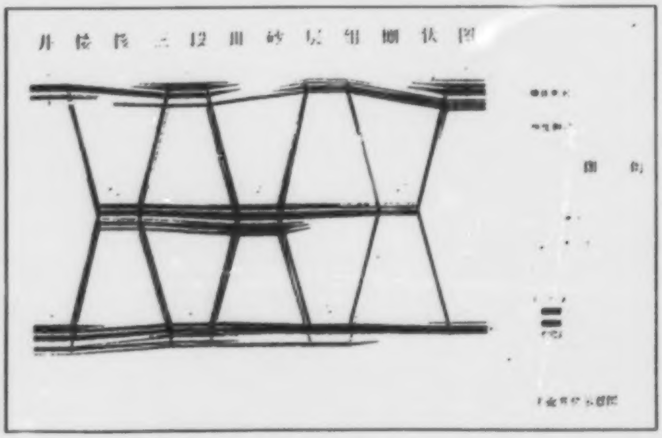

Figure 21.

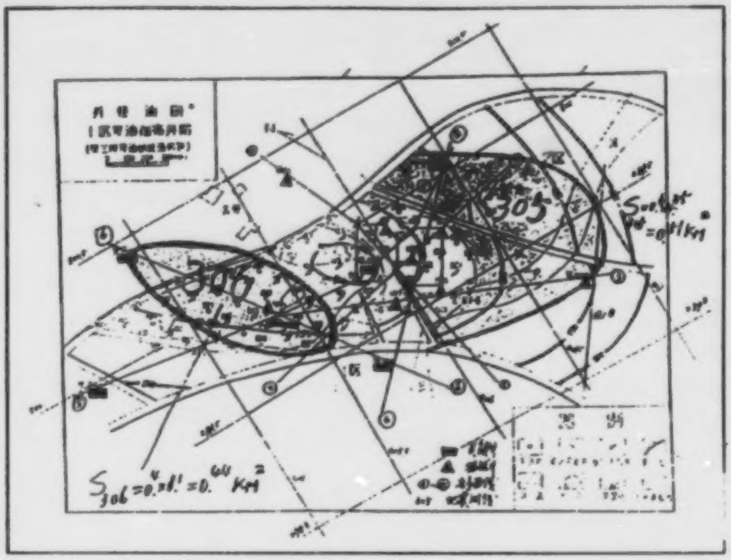

Figure 22.

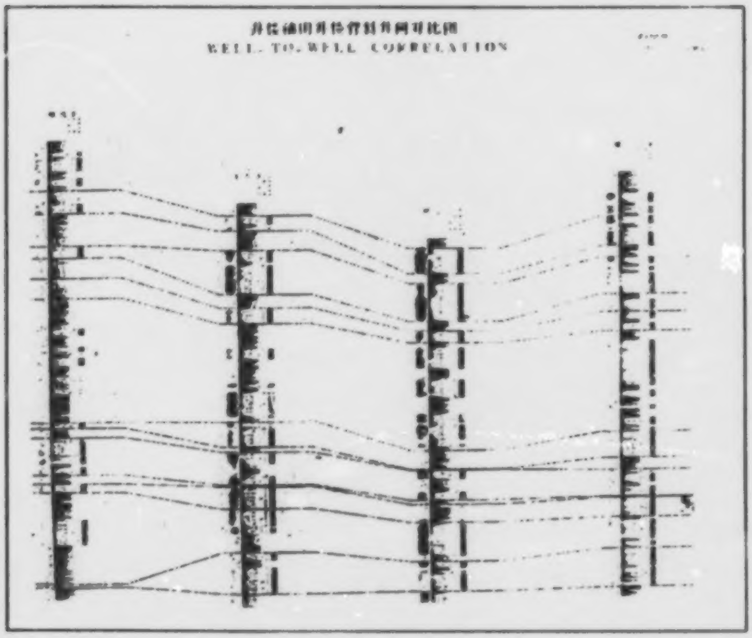

Figure 23.

Variation of geological parameters. Ten types of geological parameters such as porosity, saturation, permeability, shale content, sand thickness, productivity, reserve factor $(0_{S_o}r_o/B_o)$, and abundance $(0_{S_o}r_oh/B_o)$ are plotted and analyzed.

The parameters, 0, S_o, k, PP, ... show high values in the eastern region and low values in the west. There are high values at the structurally high area and low values at the flanks, varying basically along the direction of an ancient river channel.

The variation of geological parameters agrees with what we have discussed earlier about the variation of lithology and the reservoir fluids distribution. Both show the same trends.

Type of reservoir. In summary, Jinglou reservoir is a composite heavy oil reservoir controlled by faulting, lithology, and structure. In the east and structurally high region, the sands with coarse-grained texture, good porosity, and permeability, low shale content favor hydrocarbon accumulation and oil production. On the contrary, at both flanks of the structure and its western part, the physical properties are less favorable for hydrocarbon production. On profile No. 5 shown in Figure 23, a gas layer is apparent on the top of the fourth group of oil-bearing zones. It is also obvious that gas zone exists in Well L-127 and Well BE-1092.

The geological and geophysical features of the Jinglou heavy oil reservoir can be summarized as: (1) oil well with low productivity, generally 0.02–0.25 tonnes per day without thermal assistance; (2) high relative permeability ratio, mostly greater than 100; (3) high porosity, generally greater than 30%; (4) high oil saturation, mostly 70%; and (5) high rock permeability, generally greater than 0.1 μm^2.

CONCLUSIONS

1. The description of the Jinglou reservoir has proven the successful operation of the Reservoir Description Software Package (RDSP). Its well-built function with wide adaptability could provide various algorithms and models for users. The advantages of this package have been demonstrated by its satisfactory solution of the problems experienced in the Henan oilfield. These problems naturally exist with such complicated geological conditions, large variation in lithology, puzzling distribution of reservoir fluids, and certain difficulties associated with heavy oil.
2. The "staircase" model proposed for the procedures and methodology in reservoir description is applicable and effective.
3. Through reservoir description for heavy oil development, such as well pattern design and operation strategy in this field, the model predicted an increase in oil-bearing area by 0.94 km^2. with OOIP of about 1.729 million tonnes. This optimum development would decrease the footage of future drilling by 18,000 m. Its total economic benefit is about 70 million U.S. dollars.
4. Jinglou reservoir is the first successful application of reservoir description in China. This is a good start for future development.

ACKNOWLEDGEMENT

The authors wish to express their sincere thanks to many people, especially in the Division of Well Logging, Computer Center of RIPED for their help, and to the management of Henan oil field for their encouragement and support.

NOMENCLATURE

PI	Productivity index
Kr	Ratio of oil, water relative permeability
D_{hy}	Hydrocarbon density, g/cm^3
F_w	Water, %
W_{pg}	Weight difference of hydrocarbon, g/cm^3
S_{wm}	Movable water saturation, %
PP	Production, tonne/day
C_{11}	Confidence level of oil/gas zone evaluation by fuzzy mathematics, %
C_{12}	Confidence level of oil-water co-existing zone evaluation by fuzzy mathematics, %
C_{13}	Confidence level of water zone evaluation by fuzzy mathematics, %
R_{E_s}	Interpretation by expert system
OG	Expert system interpretation of oil/gas zone
OW	expert system interpretation of oil/water co-existing zone
W	Expert system interpretation of water zone
D	Expert system interpretation of dry zone
ρ_o	Oil density, tonne/m^3
B_o	Oil formation volume factor

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SESSION I
Reservoir Access

HORIZONTAL DRILLING

Gerry Edwards

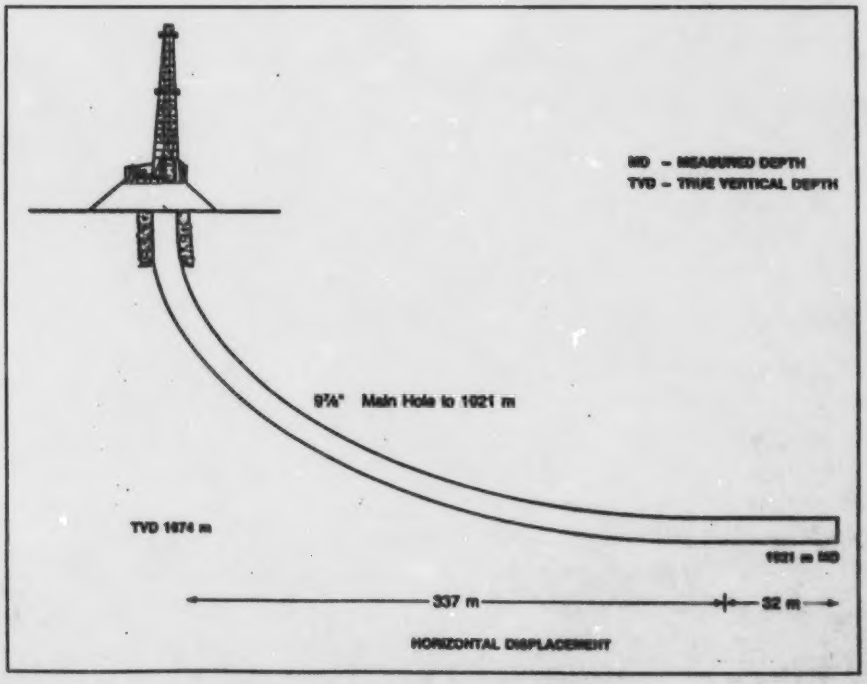
The first horizontal well bores drilled in Canada were for the solution mining of potash. Two medium radius well were drilled in 1974 in an attempt to accelerate the development of solution caverns for the mining process.

In 1978 Esso Resources Canada Limited applied the horizontal drilling technology and experience obtained in the solution mining wells to plan and drill the first horizontal well in the Canada oil industry. This long radius well was drilled into a heavy oil sand reservoir and production was assisted by cyclic steam injection. A total of 101m of horizontal section was placed in the reservoir and the well was completed with a slotted liner. Production history and experience on this well was obtained over a period of 5 years. The results encouraged the planning and drilling of a second horizontal well in the same reservoir.

The well design was again long radius with a minimum of 500 m horizontal section in the reservoir being the objective. Better than expected drilling performance was achieved in the horizontal section and a total of 1016m was drilled. This well was also completed with a slotted liner and vertical steam injection wells along the well bore length were used for production assistance. For many years this well held the record for the longest horizontal displacement versus true vertical depth.

Many more horizontal wells have been drilled in the heavy oil sand reservoirs of western Canada in the last 3 years. Numerous different completion techniques have been used, nearly all experimental with various degrees of success. Some wells have been produced by primary methods but most require some form of enhanced recovery mechanism. As the current horizontal wells provide data on heavy oil reservoir performance, many additional horizontal wells will be drilled for reservoir development.

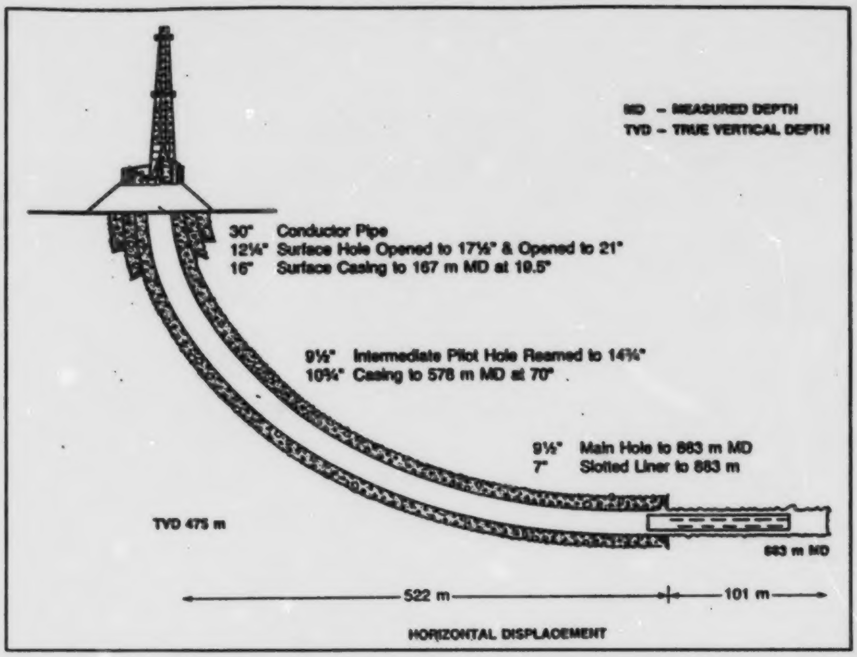
In the future more research will have to be done on reservoir characteristics, the position of the bore hole within the reservoir, and the completion method selected. It is imperative that proper planning for a horizontal well include the geological, reservoir, drilling, and production personnel. It is also very important that all of these people work as a project team. All departments should be requested to provide their latest technical input. Directional drilling



Kalium Chemicals Limited – Belle Plaine 5072.

personnel should examine offset wells to determine if specific hole problems or geological anomalies exist which would affect directional drilling operations. A complete geological profile should be prepared and any significant geological events recorded. The exact trajectory and positioning of the well bore has to be determined so that the drag and torque values may be determined. Target limits and constraints should be established and a contingency plan prepared in case of unexpected changes in the reservoir.

The drilling of horizontal wells has generally been divided into 3 different types of deviation angle build-up curves. They are long radius, medium radius, and short radius. The type of curve selected is usually dependent upon the total designed horizontal displacement with consideration if artificial lift is to be employed.


MD - MEASURED DEPTH
TVD - TRUE VERTICAL DEPTH
30" Conductor Pipe
12¼" Surface Hole Opened to 17½" & Opened to 21"
16" Surface Casing to 167 m MD at 19.5°
9½" Intermediate Pilot Hole Reamed to 14¾"
10¾" Casing to 578 m MD at 70°
9½" Main Hole to 883 m MD
7" Slotted Liner to 883 m
TVD 475 m
883 m MD
522 m
101 m
HORIZONTAL DISPLACEMENT

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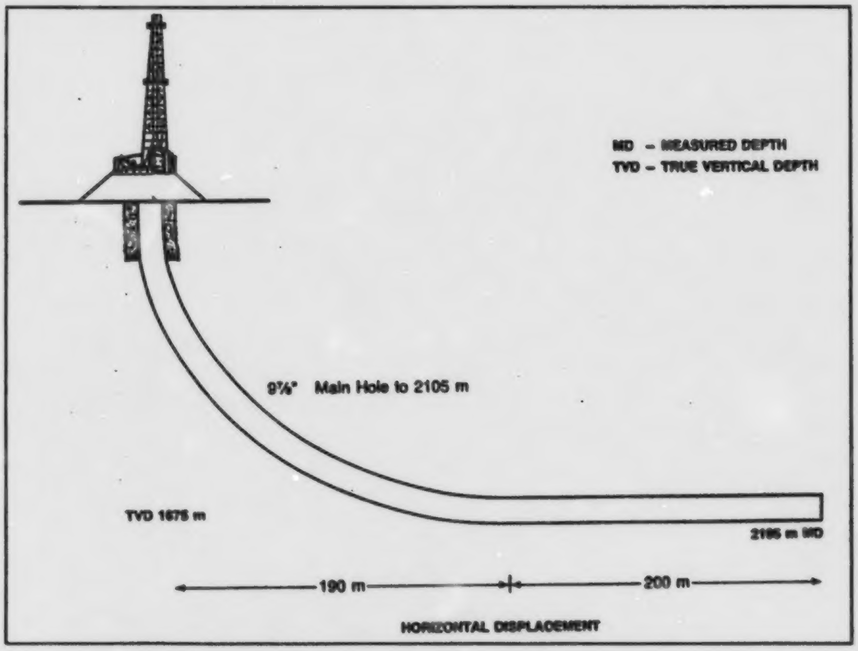
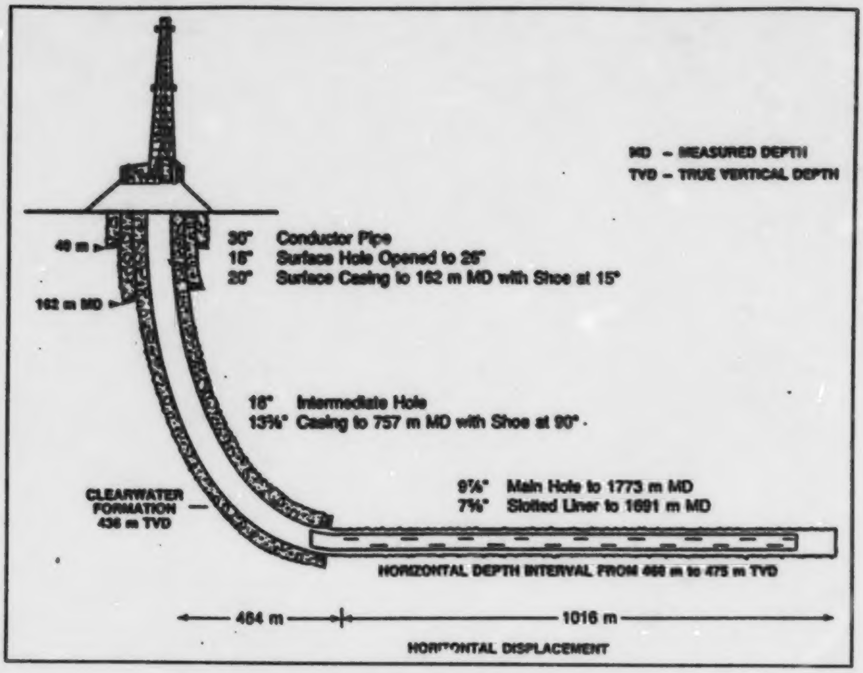

MD - MEASURED DEPTH
TVD - TRUE VERTICAL DEPTH
9⅞" Main Hole to 2105 m
TVD 1675 m
2105 m MD
190 m
200 m
HORIZONTAL DISPLACEMENT

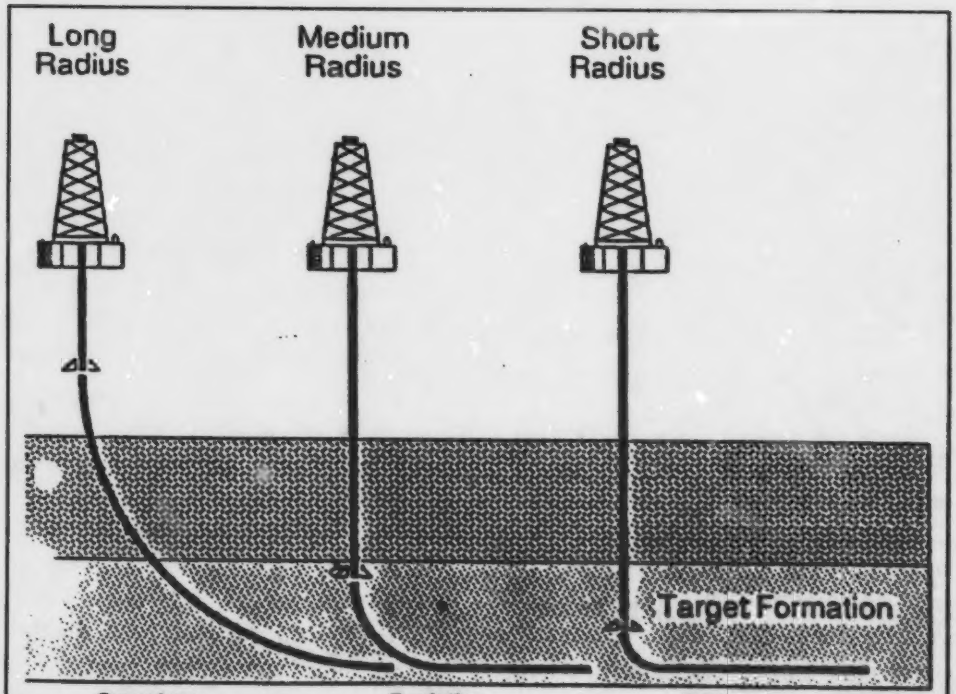
Cold Lake Horizontal Well No. 1.

LONG RADIUS

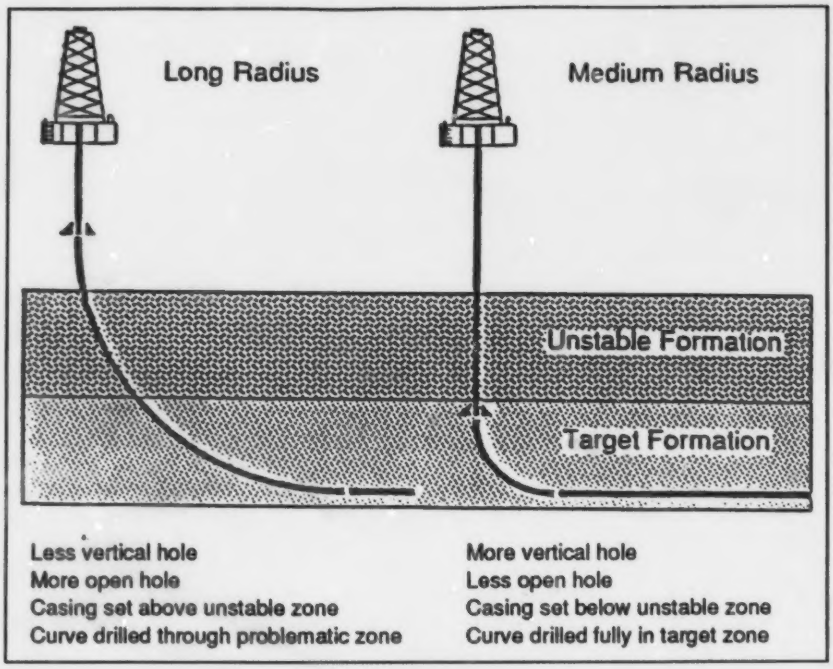
This method is particularly suitable for extended reach drilling such as offshore platform drilling, remote surface locations or withincity drilling. Conventional directional drilling equipment can be used on these types of wells, generally with build-up angle rates of from 4°/30 m to 7.5°/30 m being employed. The long radius well profile has been the most commonly used in Canada in the heavy oil reservoirs and has proven to be the most successful.


MD – MEASURED DEPTH
TVD – TRUE VERTICAL DEPTH
40 m
162 m MD
30" Conductor Pipe
18" Surface Hole Opened to 26"
20" Surface Casing to 162 m MD with Shoe at 15°
16" Intermediate Hole
13⅜" Casing to 757 m MD with Shoe at 90°
CLEARWATER FORMATION 436 m TVD
9⅞" Main Hole to 1773 m MD
7⅝" Slotted Liner to 1691 m MD
HORIZONTAL DEPTH INTERVAL FROM 468 m to 475 m TVD
464 m
1016 m
HORIZONTAL DISPLACEMENT

Cold Lake Horizontal Well No. 2.


Long Radius
Medium Radius
Short Radius
Target Formation

Curvature	**Deviation**	**Radius**
Long radius	2° to 5° per 30 m	900 m to 300 m
Medium radius	10° to 20° per 30 m	200 m to 100 m
Short radius	90° in 10 m	10 m


Long Radius
Medium Radius
Unstable Formation
Target Formation
Less vertical hole
More open hole
Casing set above unstable zone
Curve drilled through problematic zone
More vertical hole
Less open hole
Casing set below unstable zone
Curve drilled fully in target zone

Unstable formations.

MEDIUM RADIUS

This method is generally applicable in similar situations as the long radius method. More specialized directional drilling equipment must be used on these types of wells with build-up angle rates of from 10°/30 m to 20°/30 m. Also a tangent section must be incorporated into the profile design to allow for variable drilling assembly response. The medium radius curve places limitations on the size of casing that can be employed around the curve.

SHORT RADIUS

This method is very specific in application and has not been used in the heavy oil reservoirs. Very specialized directional drilling equipment must be used with this technique in achieving build-up angle rates of 9°/m. Numerous drilling assembly changes are required and control of the well bore course within the reservoir is limited. Generally this method is used for re-entry in cased well bores and therefore results in drilling a small diameter hole.

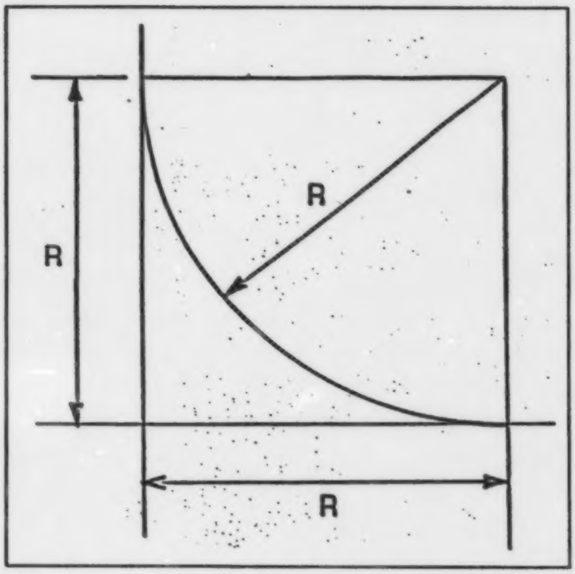
Horizontal drilling the long and medium radius well profiles is an application and extension of current directional drilling technology. The positive displacement mud motor has evolved into a highly efficient component of the total drilling process. Slow rotational speed/high torque mud motors provide sufficient mechanical energy to the drilling bit to equal normal rotary drilling parameters. Employing a connecting rod housing assembly offset at an angle to the longitudinal axis of the mud motor provides means of controlling the well bore course.

Measurement-while-drilling survey tools provide the data for positioning the mud motor relative to the well bore course for accurate placement of the well bore. Mud pulse telemetry has progressed to the level of reliability equal to that of the mud motor. Well bore deviation angle and direction, orientation of the offset connecting rod housing assembly, force on the bit and formation lithology information is transmitted to surface for analysis and subsequent adjustment in drilling parameters.

Non-magnetic "heavy-weight" is used above and below the MWD collar for accurate surveying of the well bore course. Conventional steel "heavy-

Build Curve Design Goal

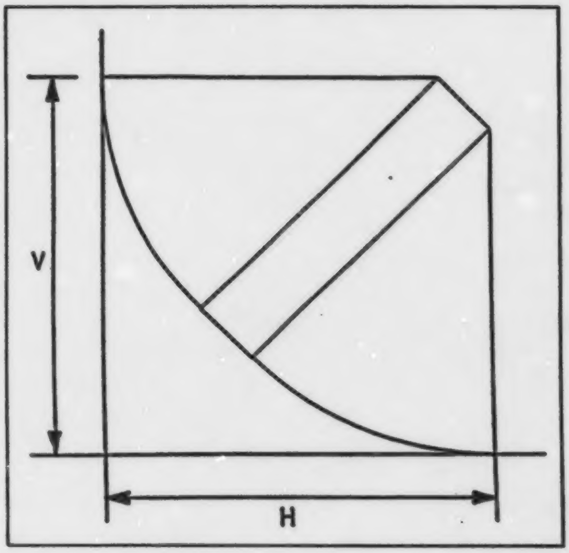
- Avoid problem formations
- Minimize the displacement of the end of the curve
- Minimize the drilled length of the build curve
- Provide an adjustment interval for handling other than the ideal build rate
- Utilize structural markers in the build intervals to adjust the final target depth
- Meet the target tolerance limits
- Provide a curve that will allow a full length horizontal hole to be drilled
- Provide a completable hole that will permit the use of al necessary production tools and equipment



$$R = \frac{5730}{B}$$

R = Radius, ft
B = Build rate, deg./100'

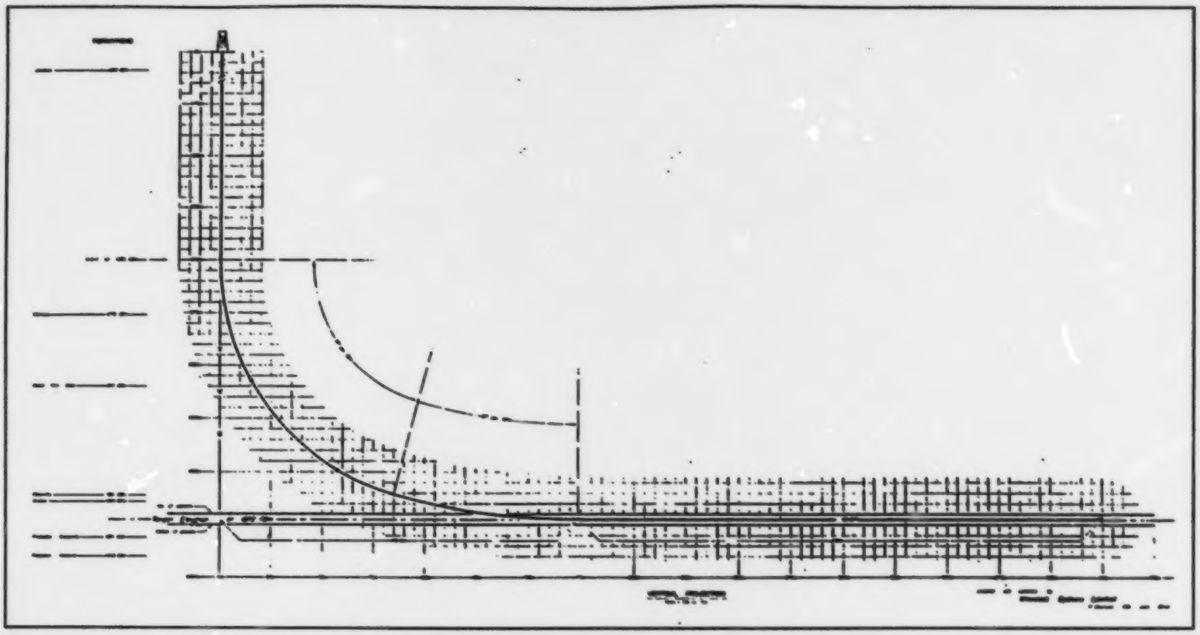
Single build curve.



Simple tangent.

weight" drill pipe is used in the drilling assembly, usually above and through the angle build-up curve. Normal drill collars may also be used in cases where additional force is required to push the drilling assembly along the horizontal section of the well profile. High strength tapered shoulder drill pipe is used between the bottom hole drilling assembly and the conventional "heavy-weight" drill pipe in the curve.

The actual trajectory of the well bore is controlled by the amount of sliding and rotating of the bottom hole assembly. When sliding, the bent housing of the mud motor is used to change the course of the well bore and the length of sliding determines the amount of change that will occur. Rotating the assembly will prevent the bent housing assembly from drilling in a specific direction and the well bore trajectory will be



Wellbore Resources Ltd. – Horizontal well profile design.

straight. Various settings of angles on the bent housing will provide differing deviation angle build-up rates. It is preferable to have the bent housing angle setting as low as is sufficient to achieve the curve design and reduce the amount of rotation.

Computer software is available to design all configuration of well profile curves. Multiple different curves should be calculated and reviewed with respect to the reservoir depth and anticipated production practices. After a curve design has been selected then drill string torque and drag calculations should be done to determine the operating limits of the drill string. Casing design should also be reviewed to ensure the casing will not be subject to failure. During drilling operations a computer should be available for survey calculations and well bore trajectory control. As drilling progresses a comparison can be made between actual well bore course and planned well bore course.

There are drilling considerations that must be reviewed in planning a horizontal well. Some of these considerations are as follows:

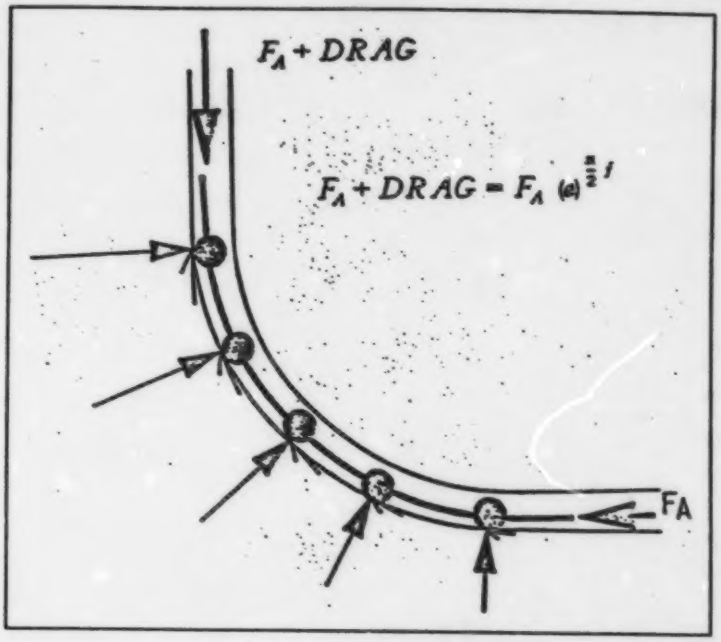
- The drilling rig equipment should be adequately sized for the well with triplex mud pumps and a kelly spinner preferred. Drilling personnel should be experienced and there should be extra personnel and equipment available.
- The drill pipe and drill collars should be in very good condition. Tubulars on horizontal wells are run reverse to what is normal, that is the drill collars are kept in the vertical section of the hole, the "heavy-weight" in the curve and drill pipe in the horizontal section.
- The drilling fluid program for the well must be suitable for the area and the reservoir. Local area knowledge and experience is most valuable in drilling fluid selection. The drilling fluid must provide well bore stability, cleaning, lubricity, formation pressure control and do minimal production formation damage. Cutting removal in the horizontal section of the well bore is most critical and this is accomplished by annular velocity. Again, drill string design is important as it must be compatible with the drilling fluid and fluid hydraulics.

Factors Affecting Torque and Drag Limits

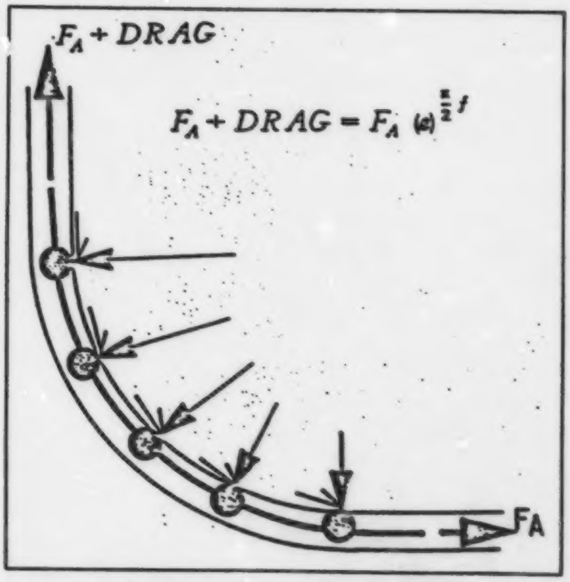
- Length of horizontal hole
- Drillstring design
  - heavyweight
  - drillpipe in horizontal hole
  - required bit loads
- Coefficient of friction
  - mud type
- Rig capacity
  - torque
  - axial
  - top drive
- Horizontal drilling technique
  - surface rotation
  - steering mode

Rotating Mode

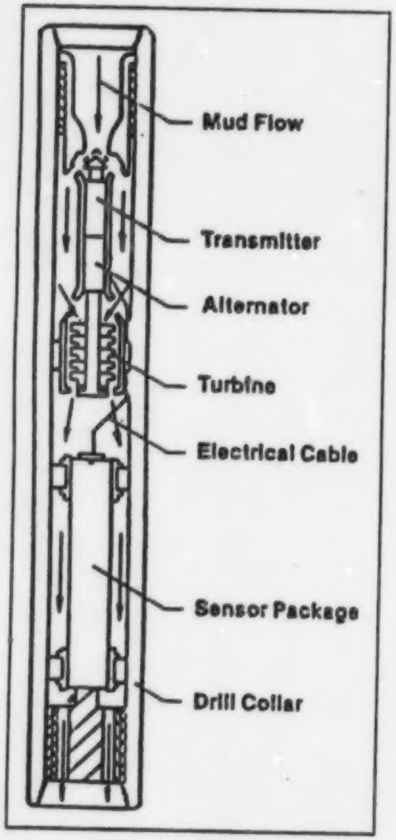
- Must avoid buckling
  - in horizontal
  - in drillpipe in vertical
- Must avoide pipe body contact in build
- Must not exceed fatigue endurance limits


$F_A + DRAG$
$F_A + DRAG = F_A (e)^{\frac{\pi}{2} f}$
FA

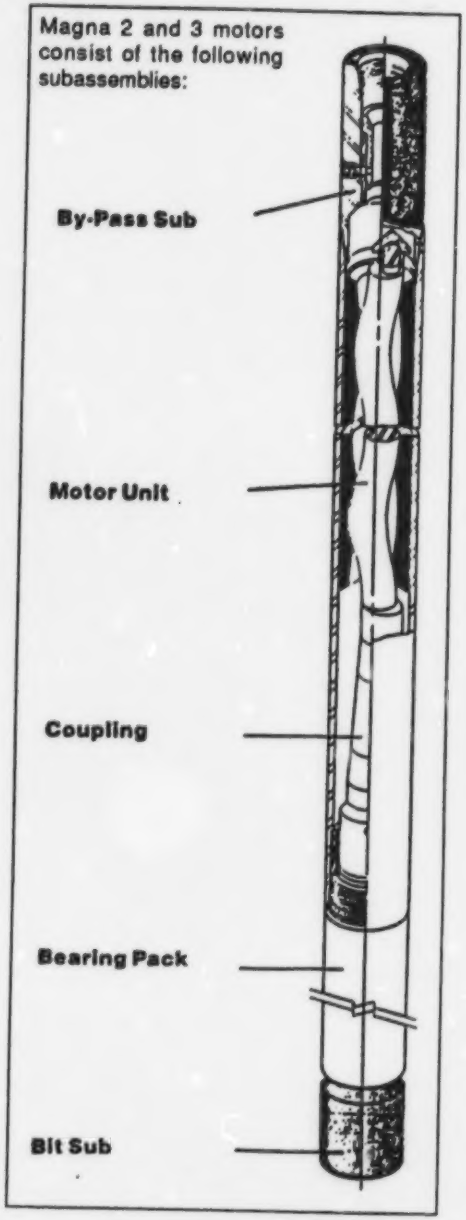
Lowering pipe around a build curve.


$F_A + DRAG$
$F_A + DRAG = F_A (e)^{\frac{\pi}{2} f}$
FA

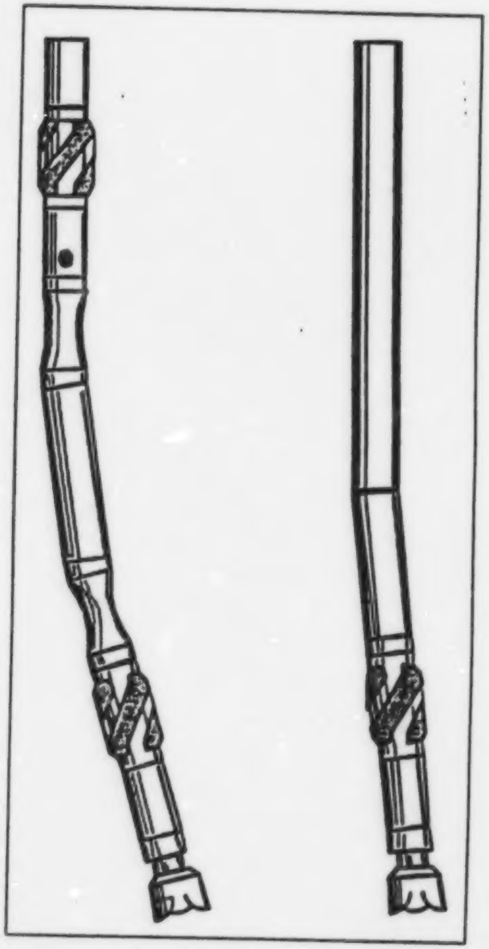
Pulling pipe around a build curve.

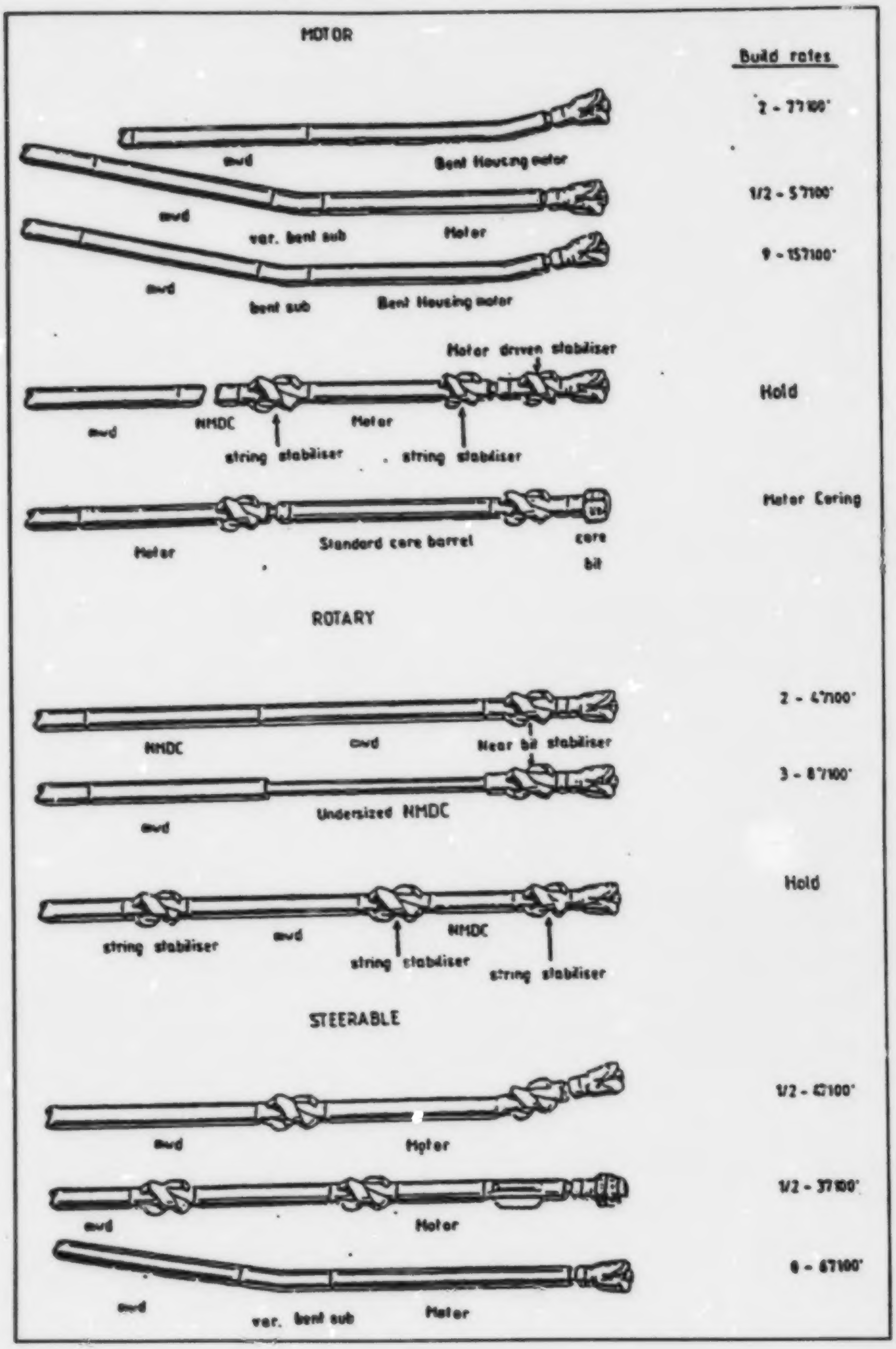

Mud Flow
Transmitter
Alternator
Turbine
Electrical Cable
Sensor Package
Drill Collar

Teleco downhole assembly.


Magna 2 and 3 motors consist of the following subassemblies:

By-Pass Sub
Motor Unit
Coupling
Bearing Pack
Bit Sub




MOTOR
Build rates
2 - 7°/100'
mwd
Bent Housing motor
1/2 - 5°/100'
mwd
var. bent sub
Motor
9 - 15°/100'
mwd
bent sub
Bent Housing motor
Motor driven stabiliser
Hold
mwd
NMDC
Motor
string stabiliser
string stabiliser
Motor Coring
Motor
Standard core barrel
core bit
ROTARY
2 - 4°/100'
NMDC
mwd
Near bit stabiliser
3 - 8°/100'
mwd
Undersized NMDC
Hold
string stabiliser
mwd
NMDC
string stabiliser
string stabiliser
STEERABLE
1/2 - 4°/100'
mwd
Motor
1/2 - 3°/100'
mwd
Motor
6 - 6°/100'
mwd
var. bent sub
Motor

- Drilling bit selection will also be selective to the area and formation types. In Canada, drill bits that would normally be used to drill a straight hole in the area are also used to drill the horizontal well. Experience has shown that special drilling bits are not required.

CONCLUSION

It is expected that the number of horizontal wells drilled in the world will increase from the approximate 200 drilled in 1989 to 4,000 by the year 2000.

Technology will continue to advance in all areas. Directional drilling control will improve as sensors are moved closer to the bit. The need for non-magnetic material may be reduced when other types of sensors are developed. Drill bits will be specifically designed for steerable motors. Advanced drilling fluids and additives will prevent differential sticking, remove cuttings efficiently and reduce formation damage. Overall drilling costs will be reduced and production and completion techniques will improve to such a degree that all oil companies will consider developing their reservoir by drilling horizontal wells.

HORIZONTAL WELL TECHNOLOGY — AN ASSESSMENT OF CANADIAN FIELD EXPERIENCE

Robert G. Farquharson
Alconsult International Ltd.

ABSTRACT

Evolving horizontal well technology and a mounting inventory of field experience are altering approaches to the assessment of reservoir performance and economic potential. Downhole drilling equipment has advanced to the point that control of the horizontal well bore is straightforward and completion techniques are improving. Focus is rightly turning to identification of optimum application and a new fresh look at reservoir engineering solutions and options.

Throughout Eastern Canada, enthusiasm is building with each new report of success. Horizontal drilling and technical seminars and courses are full. Specialized key equipment is often in short supply. Knowledge and experienced technicians are in demand.

Early Western Canada horizontal well projects tended to table the most difficult of reservoir occurrences, often heavy oil over water or under gas. The incentive generally was a large resource base with poor performance through vertical completions. With encouraging results, both technical and economic, attention is turning to other applications intending to increase recovery and productivity per drilling dollar. The improvement and competitive availability of equipment along with an experience-driven learning curve are resulting in lower costs.

This report is intended to document a growing inventory of Canadian experience with horizontal well completions, evaluating a range of problem reservoirs. For five years the number of horizontal wells drilled in Canada have increased and enthusiasts project that horizontal drilling will dominate the industry in years to come. The end objective will be to optimize economics and recovery, taking into account drainage geometry.

Horizontal well technology will not find universal application. Success rests heavily on a thorough geological knowledge of the reservoir. Production problems unique to horizontal bore holes have yet to be satisfactorily solved. Modelling, forecasting, and projection techniques await adequate experience for refinement. Results to date are, however, most encouraging.

INTRODUCTION

At the present time, the hottest topics in petroleum industry technical and trade journals relate to horizontal drilling technology and experience. This enthusiasm which has spread to the business press can be presently traced to optimistic reports from two active play areas in the United States. Horizontal bore holes are adding significant new economic oil reserves from the Austin chalk of Texas and the Bakken formation of North Dakota. In each case the reservoir was known to hold large volumes of oil in place, uncommercial from vertical completions.

Based on current activity levels and the projected plans of key developers already committed to horizontal technology, one report anticipates that horizontal wells will represent roughly 10% of all drilling activity in the United States this year. Proponents project this level of activity to increase in coming years, with the more optimistic expecting horizontal completions to challenge the 50% level by mid decade.

Horizontal technology is equipping the petroleum technologist and developer with an exciting new and refreshing look at the reservoir. The opportunity is a more precise understanding of the reservoir and management of an optimum development strategy in three dimensions. The key will lie in identifying appropriate applications.

The tools and equipment necessary to accurately place and direct bore holes through a reservoir have developed remarkably quickly. Lagging and progressing are solutions to completion and production problems of a horizontal well and the comfort of sufficient lengthy production history to confirm that objectives and projections have been met. The fundamental tools of the reservoir engineer are useful indicators of expected results, but these must be calibrated using actual field performance as it comes available.

The industry has been remarkably cooperative in developing horizontal drilling techniques in concert with service companies. Horizontal wells are planned, drilled, and controlled with a confidence already approaching that for vertical or extended reach completions. True vertical depths ranging from very shallow to better than 4500 meters (14 000 ft) have been reported. The horizontal section in the reservoir, typically over 300 meters (1000 ft) in length, has now exceeded 1600 meters (1 mile), with further advances expected. Conceptualists anticipate working in the horizontal or inclined plane of the reservoir with multiple direction completions that will further complicate the work of the reservoir analyst.

Whereas the industry has been quite open in sharing horizontal drilling technology, it has been much less so with production experience. This guarded attitude, for the most part, can be credited to a concern for competitive advantage at the present time. Those operators with actual field producing-experience are best equipped to identify economic targets likely to respond favourably to horizontal well technology. This advantage will diminish as competitors gain confidence.

This review of Canadian activity was compiled with reference to literature and media accounts, discussions with appropriate operators applying horizontal well technology, and direct experience with several significant projects. In using statistics generated from public information, one is well to remember a lesser propensity to disclose failures. Most reports are enthusiastic about the outlook for this new technology, and rightly so. One should recognize that not all attempts have met expectations and there is a great deal yet to learn through experience gained.

CANADIAN HORIZONTAL WELL ACTIVITY

In many ways, Canadian activity with horizontal well development is a reflection or parallel of general industry experience. The range of reservoir challenges tackled is broad. Horizontal drilling activity is increasing and occasional development programs incorporating horizontal well bores are starting to appear, founded on the experience of experimental tests. Included in the statistics are intermediate and long radius wells. Several ultrashort tests have been completed in Canada but are not included in this survey.

Our records show the level of horizontal well activity in Western Canada illustrated by Figure 1. Figure 2 shows the distribution of that activity. Over the ten-year span of 1978 to 1987, 21 horizontal holes were drilled with 13 of those in the last year of that period. Most of these were in heavy oil or bitumen reservoirs attempting new strategies to develop techniques to implement or improve recovery. Drilling costs were high using technology and equipment that would be considered relatively primitive compared to that quickly developed and produced over the last three-year span.

Horizontal drilling activity from 1988 to mid 1990 has increased the total number of Canadian completions to 128. Fifty-one horizontal wells completed during the first half of 1990 surpassed the record of 40 cased the entire year before. Licensed locations, announced plans, and responses to the question indicate that at least 80 more wells are reasonably firm and enough of these should be drilled this year to bring the total cased in 1990 to more than 100. This would represent roughly two percent of all wells drilled in the Western Canada sedimentary basin for the year.

Horizontal technology has attracted 38 companies active in Canada to complete wells or commit to firm plans. Three of these cased their first horizontal test in 1990 and at least 12 others are likely to do so before year end. Most of the activity can be credited

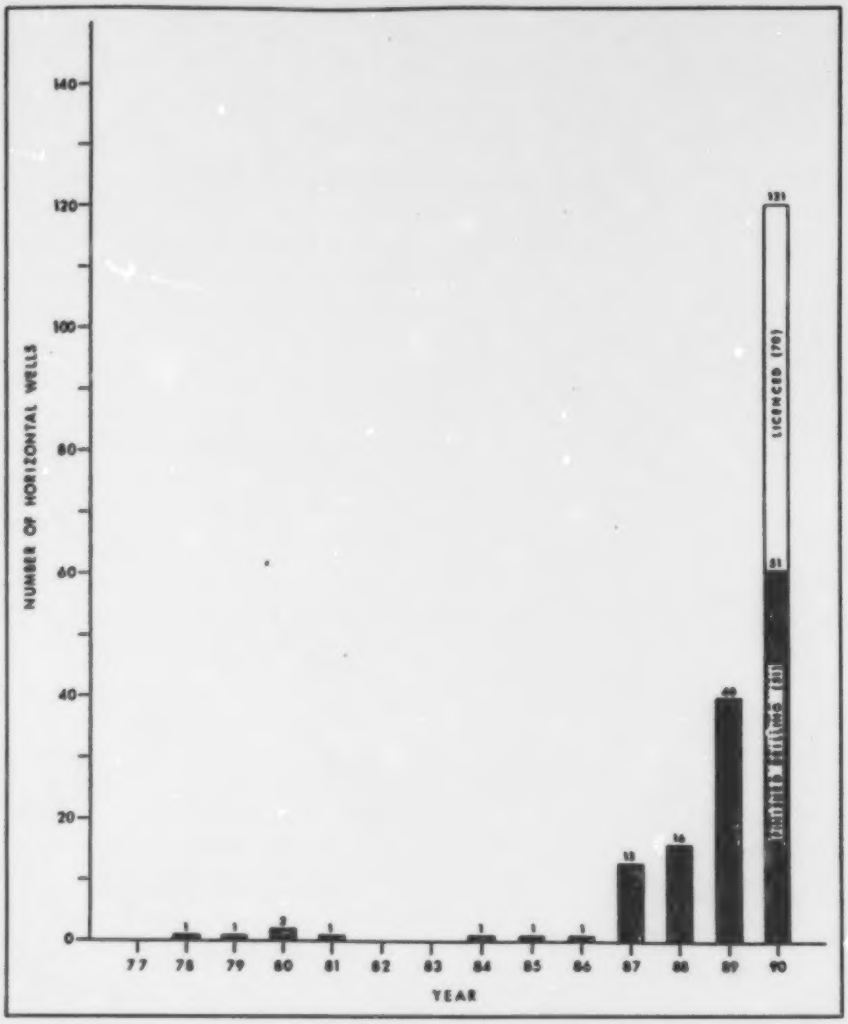


Figure 1. Canadian drilling record – intermediate and long radius horizontal wells.

industry in well count at year end.

Of 128 horizontal holes cased to mid 1990, fully two-thirds have been completed in bitumen or heavy oil sand reservoirs. Firm plans for drilling seem likely to continue that trend for the time being. Heavy oil targets have ranged in true vertical depth from very shallow to approximately 900 meters. Horizontal section in the reservoir has tended to an average of roughly 300 meters, although several holes have been extended beyond 1000 meters. One recent completion by CS Resources in the province of Alberta is a testimony to the state of development of horizontal technology. The well bore was held in a thin undulating reservoir for 1047 meters.

The remaining 43 horizontal wells drilled to mid 1990 in Western Canada tackled a variety of play types ranging over depths to 3000 meters, well short of records set elsewhere. Target formations have been clastics of the Mesozoic and carbonates of the Palaeozoic. Reservoir environments have included tight gas sands, thin gas and oil accumulations over water, fractured reservoirs, reefs, and reservoirs likely to provide accelerated economic returns at the higher production rates expected of longer penetration of the pay zone.

to junior- or intermediate-sized companies who, in accepting the added risk of applying new technology, recognize the opportunities that innovative approaches may bring.

One company, CS Resources Limited, with participation in 18 completions, is fully focused on applications for horizontal wells. The company is dedicated to the development of new technology designed to optimize recovery and economics of their investment targets. Morgan Hydrocarbons Inc. are expected to have roughly 30 horizontal wells on stream in one project area and should lead the

ECONOMICS

While the pace of horizontal well development will be influenced by resource economic realities of potential rate of return and ultimate opportunity costs, the implications are interesting. The evidence

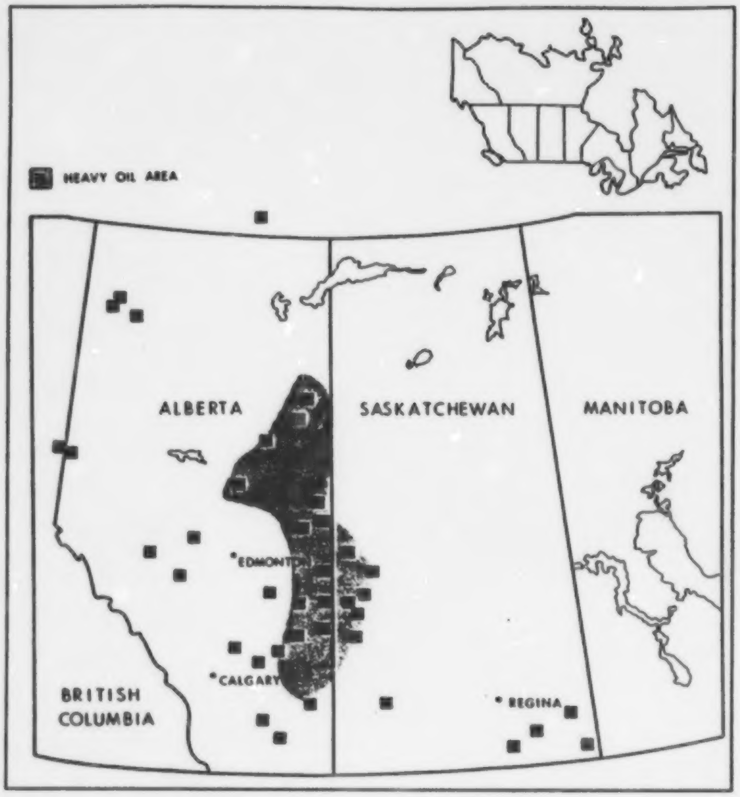


Figure 2. Horizontal well project locations.

clearly suggests that, in most instances, horizontal wells can be completed and placed on production for a cost ranging from 1.25 to 2.00 times that of a vertical offset. Engineering predictions anticipate initial well productivity of horizontal bore holes to exceed that of a vertical completion in a reservoir with appropriate character by 3 to 10 times. Some field examples have exceeded these expectations. The objective is to optimize return per drilling dollar, and in theory the potential is there to do just that.

Some applications in the right reservoir environment are quite clear. For the offshore, for example, less expensive bore holes are required to deliver a target volume of production. A similar strategy is evolving for onshore reservoirs facing development. The U.S. Austin Chalk and Bakken plays were uncommercial through vertical completions. Here horizontal well technology is creating new economic reserves. Similarly in Canada, horizontal well technology is showing interesting promise in difficult, large heavy oil occurrences, marginal or uneconomic through vertical wells.

Economics of horizontal drilling are tending to improve with the evolution of new and better equipment. The sophistication level is reaching a point where optimization of a development program is becoming a factor. Early wells in an area are rightly often optimum engineered. Cost reductions can now be gained tailoring a program to take advantage of prior experience. Figure 3 illustrates the learning curve cost experience of one operator in Canada in one development area. Deviation from such a trend is usually the result of an unexpected drilling problem.

OVERVIEW: DISCLOSED CANADIAN EXPERIENCE

Although the inventory of horizontal well experience in Western Canada is relatively small to date, public records show that many of the applications expected to develop as routine have been tried. Producing histories tend to be short relative to projected well life; however, some useful practical evidence has been made public by some operators. From a statistical point of view, heavy oil projects have dominated the scene so far.

Heavy Oil Development

Setting aside enhanced oil recovery considerations for the moment, horizontal drilling into heavy oil reservoirs of Western Canada has tackled a combination of the problems of thin but extensive heavy oil sands and heavy oil over free water or under gas. Such occurrences are common in the heavy oil region shown on Figure 2. Primary recovery is typically low and wellhead prices in an economic scenario of $20.00 US for West Texas crude are insufficient to justify development through vertical completions. Where water underlies heavy crude pay, early breakthrough generally results in premature shutdown before recovery has reached even one percent.

Our records show that horizontal wells have been drilled into 18 heavy oil or bitumen leases with a concentration of development at four. Although production histories are short, the following observations should be useful and instructive.

Heavy oil and total fluid productivity from horizontal wells tend to meet those optimistic expectations relative to performance of nearby vertical completions. Evidence supplied by CS Resources and shown as Figure 4 indicates that, in certain instances, productivity may be directly related to length of hole open in the pay zone.

A similar trend was noted at one other lease. The effect of the length of open pay is likely to be more prominent in heavy oil reservoirs than light oil or natural gas reservoirs.

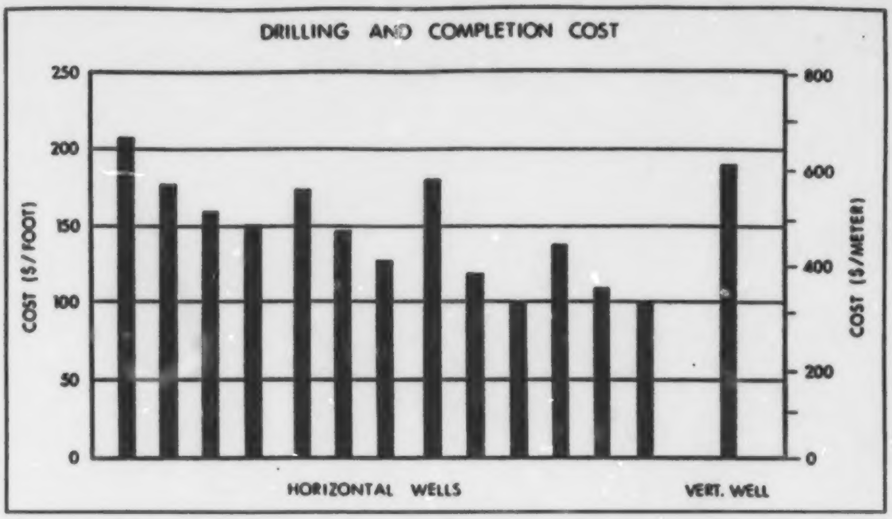


Figure 3. Drilling cost learning curve one horizontal project.

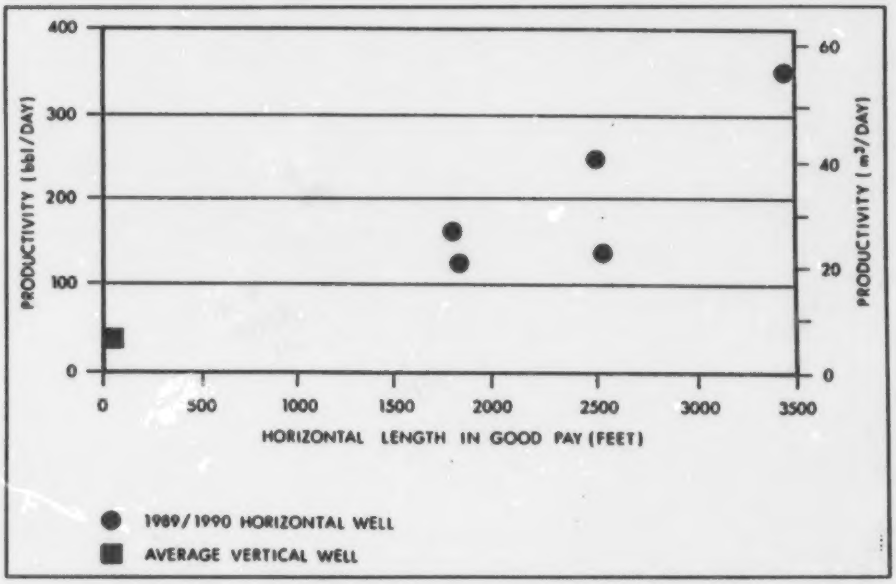


Figure 4. Initial productivity vs. horizontal length in good quality reservoir.

Primary economic reserves have been created in certain heavy oil reservoirs where development was not commercial through vertical holes. Figures 5 and 6 show production performance from two leases — one with thin pay, the other with oil pay over water, both with encouraging early life results.

Early evidence suggests that in certain reservoirs horizontal completions over water will increase recovery by reducing the effect of water coning. We note however that two operators have experienced an unfavourable primary production performance similar to that of nearby vertical wells with early breakthroughs and high water cuts.

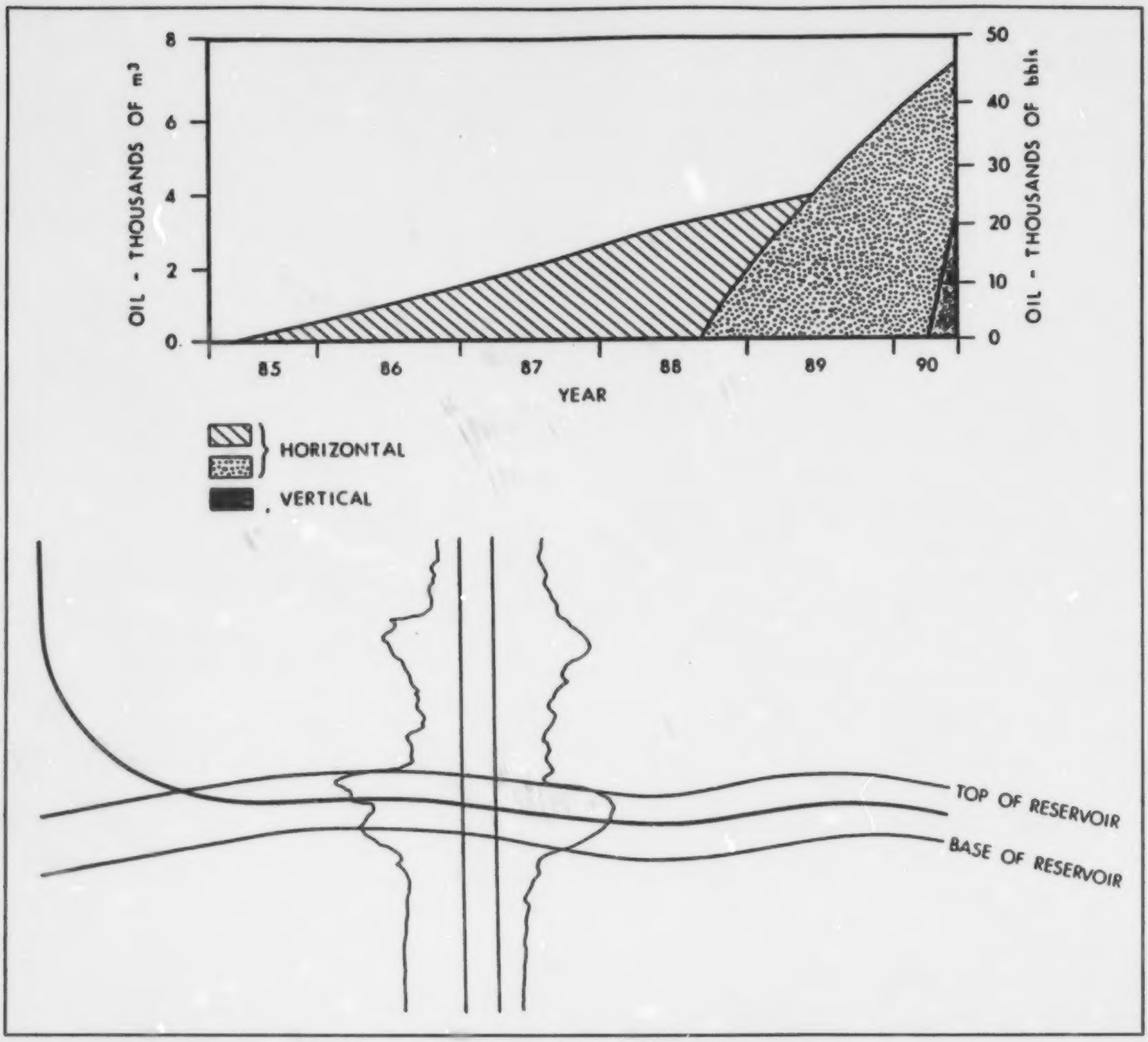


Figure 5. Cumulative oil production thin heavy oil reservoir.

We are aware of several scattered heavy oil completions that failed to better the performance of vertically completed offsets. Operators and technicians are struggling to identify reasons for these failures.

Sanding problems have not been apparently onerous in the typical loosely consolidated heavy oil sandstone reservoirs of Western Canada. More history is required to define well-bore problems and solutions.

Certain projects are showing signs of economic success, even at prevailing world prices.

On balance, the outlook to develop new heavy oil reserves using horizontal well technology looks very promising indeed. The challenge is to identify appropriate targets. Mounting field history is providing useful parameters.

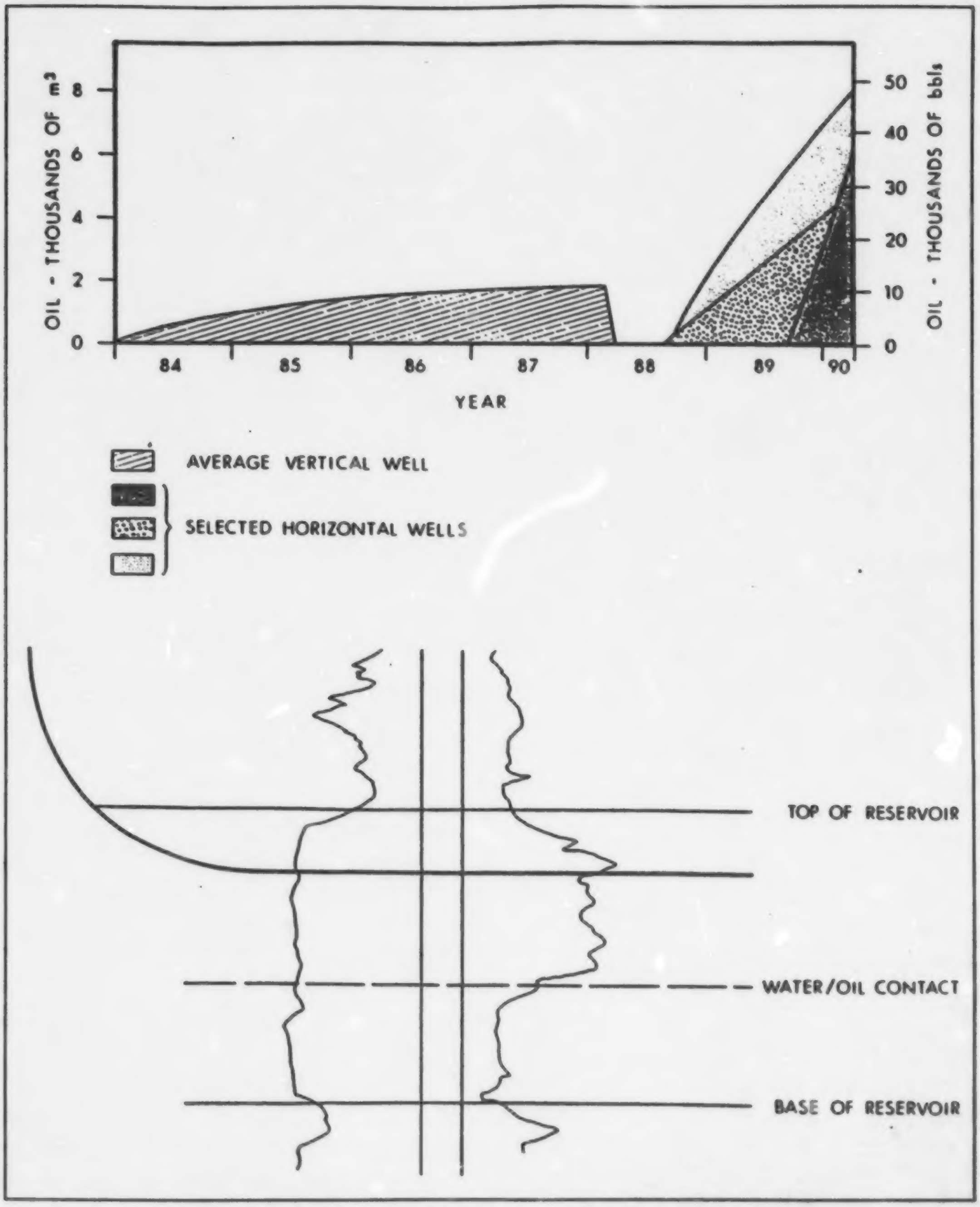


Figure 6. Cumulative oil production heavy oil over water.

Enhanced Recovery

Particularly from heavy oil and bitumen reservoirs, primary recovery will remain relatively low to negligible. Enhanced recovery considerations are likely to complicate the development plan even more in a three-dimensional analysis of the reservoir. Reservoir studies may very well show a horizontal well bore placed for primary production may not be optimum for enhanced recovery.

Several projects in Western Canada have tackled the challenge to produce enhanced recovery reserves. Of note is a horizontal Sceptre Resources Tangleflags completion of 1987 which produced at high water cuts typical of nearby vertical wells, but with high total productivity as well. Subsequent steaming into four vertical offsets has produced encouraging results, causing higher oil production rates and cuts as well as a respectable cumulative recovery projection. Further development of the scheme must await the more favourable economics of higher oil prices.

Horizontal wells have been drilled into five oil sands leases at Athabasca or Cold Lake with intent to steam cycle. Further experimenting is likely and may evolve as a strategy when oil prices are more favourable.

from the AOSTRA underground test facility at Athabasca is adding a new prospective. Short horizontal well pairs drilled into bitumen pay from a drift below the oil sand is testing a steam-assisted gravity drainage scheme that may well find application using surface wells. Published data suggests recovery is encouraging and economics may challenge those of other rival oil sands alternatives.

Other Areas

Forty-three horizontal wells had been drilled at scattered locations across the Western Canada sedimentary basin to mid 1990 with a certain degree of concentration and objectives. Our discussions and review have led to the following observations.

- Thirteen horizontal wells have been drilled into carbonates of Mississippian age in southeast Saskatchewan by seven different operators. Although production data in the public domain is scarce, further activity is planned. Several Mississippian completions are substantially out performing the average vertical well, while several must be counted as disappointments. Mississippian reservoirs tend to be stratified, and horizontal drilling across strata boundaries at high angles to open a full section has apparently presented some problems.
- Our records indicate that but 8 horizontal wells have been drilled into gas-prone reservoirs with the intent to test application of the technology. Four of these were designed to exploit a thin reservoir edge over water in a Cretaceous sand. In the deep basin, Canadian Hunter have expressed disappointment in their attempts to expose a fracture system in low permeability Cretaceous reservoir rock.
- Five horizontal wells have been drilled into Rainbow reefs as a development strategy. Public production information shows recovery at commercial rates.

The remaining tests are scattered through the basin drilled into low permeability or otherwise problem reservoirs.

SUMMARY AND OUTLOOK

Application of horizontal drilling technology is off to a respectable start in Western Canada. Projects initiated or planned have tackled a variety of reservoir scenarios thought to hold promise for exploitation using horizontal bore holes with ingenuity. Equipment and services have developed to the stage that a horizontal well bore can be placed accurately and extended to the limits of records already set. Canadian companies are developing new and innovative improvements.

To plan and drill a horizontal well is very much the effect of a team. Experience is a significant asset. A rigorous well plan is best implemented by a knowledgeable and practiced technician. A key team member is the wellsite geologist who in consort with wellsite engineers and service technicians must steer the drill string to intersect the formation at the desired level and along an optimum drilling plane.

Information from horizontal wells is providing a new look at the lateral structure of reservoirs. Some unpleasant surprises may well be avoided by detailed mapping. We have recorded examples of wandering from undulating sands, exiting pay zone prematurely, and encountering dense or impermeable barriers unexpectedly. In some cases, such variants have been later identified on 3-D seismic. Prior knowledge of the reservoir gathered and interpreted can reduce costly changes of plan.

Innovative production equipment is developing along with techniques to attack production problems in horizontal drains. Operators are increasingly able to implement well clean outs, isolation of reservoir section, and even focused water shut-off. Such operational gains are likely to continue at a meaningful pace.

It is in the areas of well bore and reservoir performance that more field experience is required. Lateral variations in the reservoir and wandering of the well bore are likely to affect production performance in a material way. From a macroscopic point of view, field performance experience is required to calibrate the excellent modelling tools available to the reservoir engineer if we are to develop the science to the state of true reservoir management in three-dimension with the intent to optimize recovery as well as economics. Reservoir evaluators are able to define those settings most likely to outperform conventional development but as yet without a degree of certainty.

From a review of activity to date and the enthusiasm of proponents, it is easy to predict a significant future for applying horizontal technology in Canada. Heavy oil and oil sand applications are likely to lead the list; however, other applications will follow any economic success.

ACKNOWLEDGEMENTS

The author wishes to thank those companies who openly provided useful information and particularly C.S. Resources Limited and Morgan Hydrocarbons Inc. Also very helpful was the assistance of P.C. Wang, P. Geoph., in gathering and analyzing certain statistics.

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THE SHAFT AND TUNNEL ACCESS CONCEPT

H.G. Stephenson
Norwest Mine Services Ltd.

SYNOPSIS

The Underground Test Facility, constructed and operated by the Alberta Oil Sands Technology and Research Authority (AOSTRA) near Ft. McMurray, Alberta, Canada, has tested a new process for recovery of bitumen from oilsands. The Shaft and Tunnel Access Concept (SATAC) utilizes tunnels located below the reservoir and accessed by vertical shafts. Horizontal wells drilled from the tunnels are used for injection of steam and production of bitumen.

The first pilot test, carried out by AOSTRA and seven industry partners, has been extremely successful, providing a recovery of more than 60 of the oil in place from this abundant but difficult reservoir. The economics of the SATAC process appear to be comparable with the best of surface well systems or with surface mining of oil sands. Advantages of the system include the efficient use of heat, (which rises from the wells to mobilize bitumen in the reservoir), and the use of gravity drainage from horizontal production wells having a high exposure to the pay zone.

A full scale pilot test, using commercial length horizontal wells, is being implemented in 1990.

The Underground Test Facility and the SATAC process have been developed by AOSTRA using Alberta based Canadian engineering and consulting companies. The author of this paper, Mr. H.G. Stephenson, is President of Norwest Mine Services Ltd. which was responsible for conceptual design and costing and managed the construction of the Access Stage. Norwest now acts as mine operations managers for the AOSTRA/Industry consortium.

INTRODUCTION

Total reserves of bitumen in the oil sands of the Province of Alberta, Canada are believed to be 250 billion m^3.[1] this is one of the world's largest reserves of liquid hydrocarbons, comparable with those of conventional oil reserves in the Middle East.

Canadian oil companies and governments have expended hundreds of millions of dollars on research and development in an attempt to identify methods of successfully exploiting this vast resource.

The methods utilized fall into three quite distinct categories:

Using very large excavators and conveyor systems to mine shallow oil sands and transport it to a processing plant.

Surface mining and processing has been commercially and technically successful over the last decade. Unfortunately in the largest and most difficult reservoir, the Athabasca, the system is only profitable at very shallow depths which includes, at the most, 5% of the oil sands reserves in Alberta.

Drilling of wells from the surface and application of a variety of in situ recovery techniques.

Surface wells have been used successfully on a commercial scale in the two smaller fields, Cold Lake and Peace River, operated by Esso and Shell respectively. Attempts to utilize surface wells in the Athabasca have been unsuccessful due to the extremely difficult reservoir conditions. This highly variable reservoir contains extremely viscous bitumen (5 million cp) which renders the formation impermeable under reservoir conditions.

The use of shafts leading to tunnels located below the oil sand from which horizontal wells are drilled. In situ techniques using steam are applied to mobilize the bitumen allowing it to drain by gravity to a pipeline system in the tunnels.

The Shaft and Tunnel Access Concept, SATAC for short, has been applied on a pilot scale at a single location in the difficult Athabasca field and has proven very successful. Recoveries of oil in place have been exceptional and projections of economics for a commercial operation, based on the results of the pilot, are very encouraging.

The remainder of this paper is devoted to a description of the SATAC concept applied at the Underground Test Facility and is complemented by other papers, to be presented at the symposium which describe the steam assisted drainage operation applied from the tunnels and the monitoring and simulation of the pilot operation.

NEED FOR AN UNDERGROUND TEST FACILITY

When AOSTRA was founded in 1974 the development of in situ technology for Alberta's oil sands reserves beyond surface mining limits was the primary objective. In 1976 AOSTRA began a series of paper studies which examined the use of underground mining technology to place tunnels in or near the pay zone of oil sand reservoirs with the objective of locating personnel and equipment close to the reservoir. These studies indicated that two basic principles made this approach advantageous namely;

- heat rises, and
- liquid flows downhill.

The studies showed that if steam was injected into a well drilled at the base of the pay zone the natural tendency for heat to rise and the reduction of heat loss to non oil bearing strata would result in very efficient utilization of energy.

Moreover, drilling the well from a tunnel just below the reservoir would encourage the heated bitumen to drain by gravity to the pipeline system for transportation to the surface.

The studies also indicated that for the above reasons, and because virtually all of the drilling was within the pay zone, the recovery of oil in place was likely to be significantly higher, and the cost of steam would be less, than for conventional in situ operations.

These studies continued until 1982. At this time it became clear that, if the conclusions of the studies were to be confirmed in practice, an Underground Test Facility (U.T.F.) would be required to carry out pilot testing.

Consequently in 1982 the Board of AOSTRA commissioned Norwest to prepare development proposals including costs and designs for the U.T.F. In 1984 AOSTRA decided to construct the access facilities and to engineer the Phase A Pilot operation. Norwest were appointed Project Managers for construction of the Access Phase on a site near Ft. McMurray in Northern Alberta.

DESIGN AND CONSTRUCTION OF THE U.T.F.

Planning and engineering for the Access Phase of the U.T.F. has been described in detail by Stephenson et al.[2] and is summarized below.

The Shafts

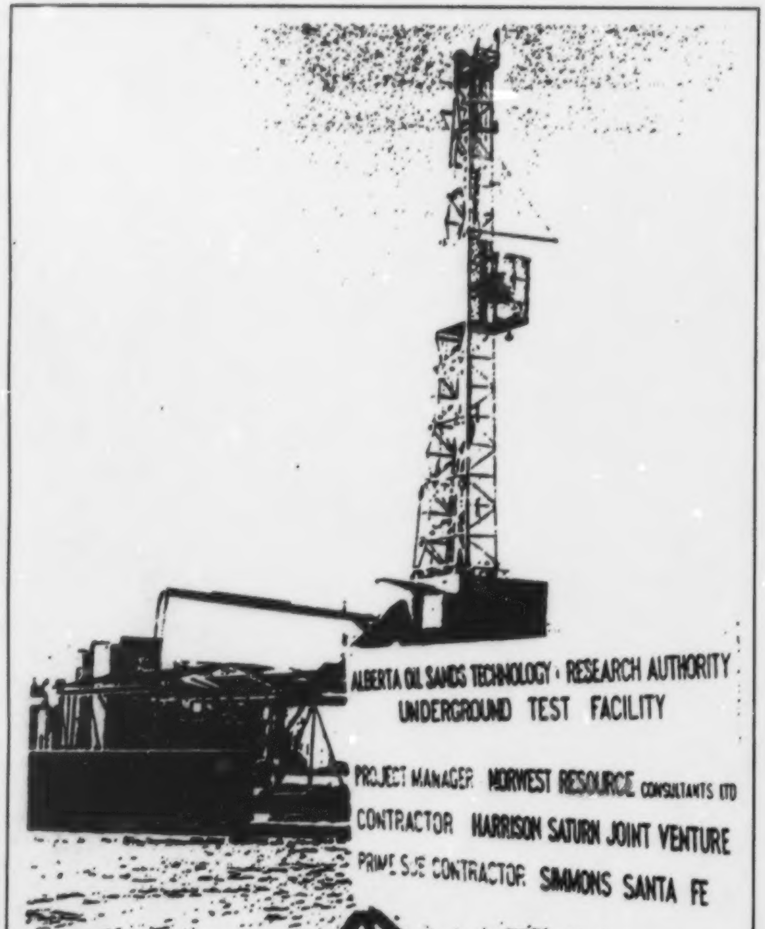
It was decided that two shafts, each 3 m finished diameter and 213 m deep, were required. The shafts were to be hydrostatically sealed and supported by a steel liner. Geotechnical investigation showed that the strata to be penetrated included;

- overburden which consisted of soft, weak, clayey and silty deposits,
- the oil sands which were prone to release of gas and slabbing and,
- limestone below the sands.

This was clearly a very difficult shaft sinking proposition and blind shaft drilling was adopted as the method of choice.

A conventional deep hole oilfield rig with a 500 t hook load was modified to carry out the drilling of shafts and placement of liner (Figure 1). A 4 m diameter bit assembly weighing 250 t was used (Figure 2).

The shaft construction has been described in detail by Patterson et al.[3] The shafts were completed on schedule, the first shaft being drilled and lined in only 211 months.



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UNDERGROUND TEST FACILITY
PROJECT MANAGER NORWEST RESOURCE CONSULTANTS LTD
CONTRACTOR HARRISON SATURN JOINT VENTURE
PRIME SUB CONTRACTOR SIMMONS SANTA FE

Figure 1. Rig for blind shaft drilling.

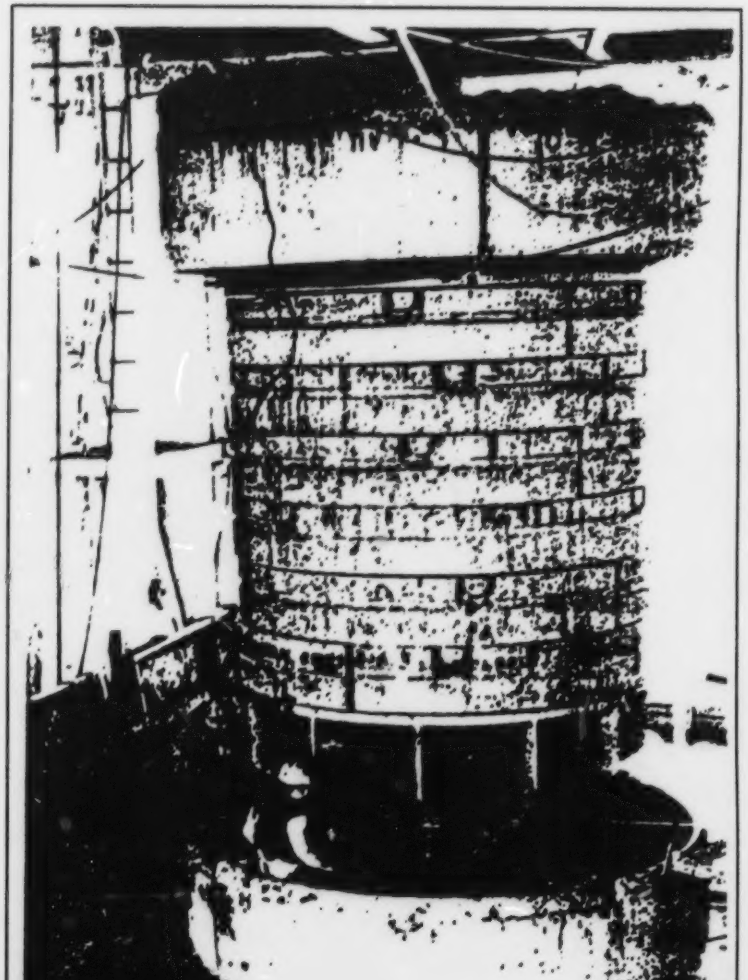

Figure 2. The bit assembly for blind shaft drilling.

The Tunnels

A tunnel horizon was selected 13 m below the base of the reservoir. Tunnels were driven 5 m wide by 4 m high using drilling, blasting and loading techniques. Figure 3 shows a section of the 980 m of tunnels driven for the Phase A pilot. Support services within the tunnels included air, water, electricity, equipment assembly station, rock handling facilities and a refuge chamber. Roof support was by 2.1 m long roof bolts on a 1.5 m grid.

DRILLING THE WELLS

A prototype drill rig was constructed to drill the wells from the tunnel. The rig, shown in Figure 4, was designed to both drill and complete the wells, installing special casing to permit steam injection and bitumen production. The rig is an electrohydraulic, self propelled, track mounted unit designed to operate in the confined space of the tunnel and in an atmosphere which has the potential to be explosive. The rig has a maximum thrust of 100 t and is capable of drilling 222 mm horizontal holes to a depth of 600 m. Equipment is provided to survey the hole and modify the direction of the drill bit. All drilling was done through a blow out preventer connected to a 40 m long, 244 mm diameter casing cemented in position.

THE IN SITU PROCESS

Two separate in situ processes were piloted during the Phase A program. The steam chamber will be described in detail by Dr. R.M. Butler in a paper to be presented to this Symposium. The Chevron HASDRIVE process has also been tested. This paper deals primarily with the application of the steam chamber process.

The steam assisted gravity drainage process applied to the steam chamber at the U.T.F. has been described by Edmunds.[4]

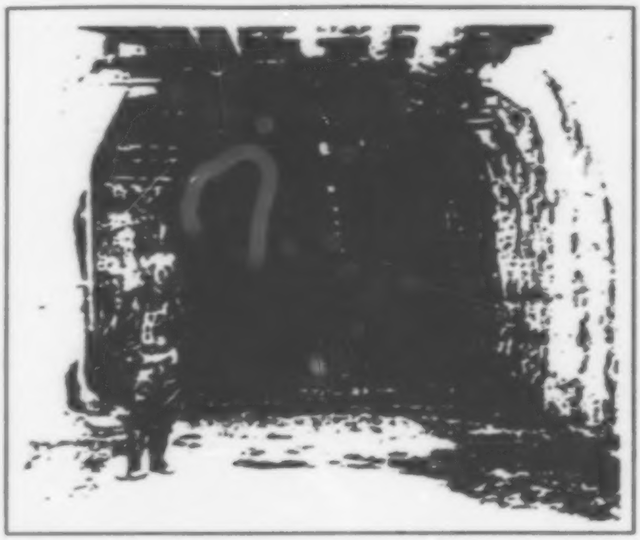

Figure 3. A typical tunnel.

Wells were drilled in pairs with the producer well near the base of the reservoir and the injector about 5 m above it. As steam was injected steam travelling to the edge of the chamber would heat the undepleted sand at the boundary. The bitumen would be mobilized and would drain to the production hole with the condensed steam.

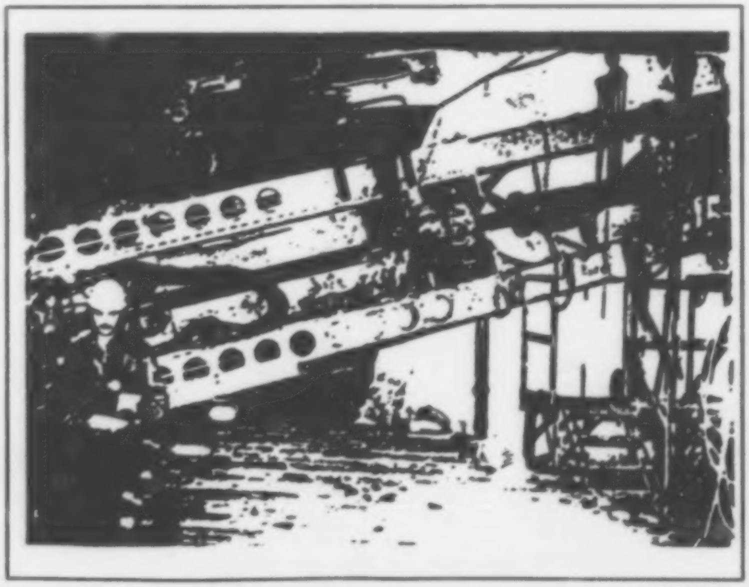

Figure 4. The underground drilling rig.

Three pairs of wells were drilled 27 m apart with an effective completed length of 60 m in the reservoir. The spacing of well pairs is selected so as to cause the steam chambers to connect as the full height of the pay zone is reached.

PHASE A IMPLEMENTATION AND PERFORMANCE

The Phase A Pilot was implemented when steam injection began in late 1987.

Results from field testing have been extremely encouraging and have been described in a paper by Haston, Luhning et al.[5] of which a summary follows. The most encouraging aspects are the high recoveries of oil in place and the very efficient use of steam.

When the SATAC concept was first examined and planning of the Phase A Pilot was underway recovery of oil in place was expected to fall within the 30–50% range. Subsequently, numerical simulation of process mechanisms were carried out during the implementation of Phase A and indicated that recoveries would be near the upper end of this range. Actual recoveries of oil in place have exceeded 60% for each of the three well pairs. The recovery has been achieved over approximately two years, considerably less than the four year period expected. Steam oil ratios have been extremely low.

PARTICIPANTS

During Phase A seven additional participants joined AOSTRA at the U.T.F. They are the Canmet division of the Federal Energy Department as well as Chevron Canada Resources Limited, Texaco Canada Resources Ltd., Mobil Oil Canada, Ltd., Petro-Canada Inc., Shell Canada Limited and Amoco Canada Petroleum Company Ltd.

AOSTRA will continue as the operator during Phase B.

PHASE B PILOT

A full scale pilot test of commercial length wells 600 m long has been approved by AOSTRA and its industry partners. This Phase B pilot has or will involve:

- construction of an additional 550 m of tunnel (completed July 1990),
- drilling of three pairs of wells 600 m long at 70 m centres (underway August 1990),
- expansion of the process facilities (underway),
- steaming of three well pairs (expected to begin in spring, 1991 and to be completed in 1993).

The layout of Phase B is shown in Figure 8.

COMMERCIAL PLANT DESIGN

The main features of a commercial SATAC operation have been described by Haston, Luhning, et al.[5]

Nominally production would be set at 1600 m^3/d of bitumen. This level achieves economies of scale yet fits the immediately available reserves. It utilizes the existing Underground Test Facility as a base with significant additional tunnelling and drilling.

Design of the expansion would begin in 1994, commercial operations would begin in 1996, and full capacity would be reached in 1996. The operation would utilize 70 well pairs over a life of at least 16 years.

ECONOMICS OF COMMERCIAL OPERATION

The economics of a commercial application on the U.T.F. lease have been examined and described[5]. Figures given below are taken directly from this paper. All costs are in 1989 Canadian dollars.

Table 1 summarizes the capital and operating costs.

The production cost for this commercial operation is shown in Table 2.

ACKNOWLEDGEMENT

The author wishes to thank AOSTRA for permission to publish this paper and to quote the data presented.

Table 1. UTF expansion capital and operating costs (1989 Canadian dollars)

Capital	
Mine extension	$28,700,000
Drilling and completion	56,000,000
Underground facilities	29,580,000
Surface facilities and pipeline	40,920,000
Total capital	$155,200,000
Annual operating	
Fuel	$10,500,000
Operations and maintenance	10,000,000
Diluent loss	1,000,000
Pressure maintenance	700,000
Total operating	$22,200,000

Table 2. Production cost

	AOSTRA U.T.F. 4/bbl	%
Surface plant	1.61	15
Mining/drilling	1.85	17
Additional wells	1.03	9
Fuel ($2.50/GJ)	2.87	26
O&M	3.69	33
Total	10.88 ($63.30/m^3)	10

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THE SCALED PHYSICAL MODEL STUDIES OF HORIZONTAL FRACTURE-ASSISTED STEAMFLOODING SUPER HEAVY OIL

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ABSTRACT

This paper discusses the scaled physical model studies of horizontal fracture-assisted steamflooding super heavy oil, which viscosity at reservoir temperature is about 1,000,000 centipoise (mPa·s). The results indicate that these horizontal fractures could create heat communication paths between the injection and production wells. When these fractures are built in the lower part of the oil zone, the steam gravity segregation can heat oil column efficiently, thus resulting in a higher oil-steam ratio and higher oil recovery.

The optimum steam injection rate was selected through the scaled modeling experiments. After each test, the residual oil saturation in the model was measured. The results indicated that the distribution of residual oil saturation was affected by steam injection rates.

The studies show that horizontal fracture-assisted steamflooding super heavy oil is feasible.

INTRODUCTION

There are 900 billion tonnes of heavy oil reserves, which is almost three times more than the light oil reserves (360 billion tonnes) throughout the world. According to Liu's heavy oil classification and standards, China has plenty of heavy oil reserves, of which, 40% is normal heavy oil, 12% is special heavy and 48% is super heavy oil. The normal heavy oil could be successfully developed by using existing technology. For special and super heavy oil however, producing these kinds of crudes needs certain innovative approaches. Super heavy oil, especially with viscosity greater than 50,000 cp is almost immobile at reservoir condition and impossible to be flooded by the conventional way using steam. Thus, for an actual super heavy oil reservoir with oil viscosity at reservoir temperature of about 1,000,000 cp, a more efficient means must be found to recover such crude. This paper discusses the studies of horizontal fracture-assisted steamflood technology by using a scaled physical model to simulate recovery mechanism for the said oil.

BRIEF DESCRIPTION OF HORIZONTAL FRACTURE-ASSISTED STEAMFLOOD TECHNOLOGY

Super heavy oil also refers to tar or bitumen. Several oil companies in the world have tested or are testing the technique of horizontal fracture-assisted steamflooding tar. For an example, CONOCO had a field test at the Sanner Ranch field (South Texas) in 1981. The reported tar viscosity at the reservoir condition was about 20 million centipoise. Note that this tar can not be recovered by a conventional steam stimulation. Throughout 23 months operation, 21, 200 m^3 of tar was produced with oil-steam ratio of 0.125 and recovery of 47%. This indicates that the horizontal fracture-assisted steamflood technology is a new approach and is very attractive for recovery of super heavy oils.

Britton[3] summarized the said operation procedures as these: Firstly the production casing in the lower part of the target zone in the oil wells was circumferentially notched by using an abrasive sand jet. Then the formation in the wellbore area was horizontally fractured (abrasive sand jet technique). This can be done in some shallow reservoirs, in which, the vertical formation stress is weaker than the horizontal formation stress.[4,5]

Table 1.

Parameter	Model	Prototype	Scaling ratio
Length	43 cm	100 m	1/232.6
Thickness	9.3 cm	21.6 m	1/232.6
Permeability	800 μm^2	3.5 μm^2	232.6
Time	1 min	37.5d	$1/(232.6)^2$
Rate	1 cm^3/min	1.34 m^3/d	$1/(232.6)^2$
Porosity	0.385	0.83	
Temperature	15°C	15°C	
Dip	0°C	0°C	
Pattern	inverted 5-spot	inverted 5-spot	
Viscosity	1,000,000 cp	1,000,000 cp	

SCALED PHYSICAL MODELING OF HORIZONTAL FRACTURE-ASSISTED STEAMFLOODING SUPER HEAVY OIL

Brief Description of the Model

The model used is a high pressure scaled physical model which was designed based on the scaling theory. According to this, the following conditions must be met.

1. Model and reservoir must be geometrically similar. That is the width-to-length ratio, height-to-length ratio, dip angle, and reservoir heterogeneities between these two are the same.
2. The values of rock and fluids properties, as well as of parameters related to the transport of heat and mass, must be equal in the reservoir and model.
3. Model and reservoir must have the same initial and boundary conditions.

The scaling group can be met easily when using actual prototype reservoir oil. The other scaling parameters are listed in Table 1. According to Pujol and Boberg,[6] this kind of physical model can be used successfully to simulate the process of steamflooding heavy oil.

The model we used was an open type with a quarter of an inverted five-spot pattern. This simulator had not only all the capability of conventional models, but also possessed special abilities like modeling fractures, reservoir heterogeneity, and measuring the distribution of residual oil saturation after the tests. As the Figure 1 shows there are 48 thermal couples in the model, these can be used to measure temperature distribution at any time during experiments. The model was insulated by an insulated glue to simulate the boundary conditions.

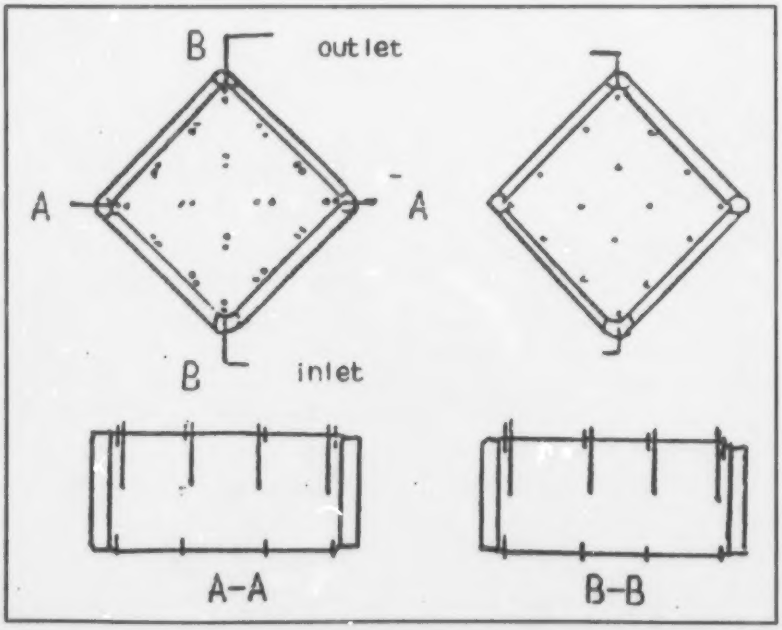


Figure 1. Diagrammatic sketch of thermocouples distribution.

In model studies, it is difficult to simulate the horizontal fracture, which is usually done by using high permeability thin layer. In our case, however, the super heavy oil with viscosity of one million cp simply would not flow through that layer. In fact, our horizontal fracture was modeled by using thin water zone with very high mobility due to its low viscosity. Moreover, the water zone had the same permeability as the oil zone, thus, we were able to simulate the hydraulic fracture without propant and closing of the fracture.

Experimental Procedures

1. The model was packed by selected sands and closed tightly. Then it was put in a container with constant temperature.
2. The model was firstly vacuumized, then saturated with water, which was finally displace by reservoir oil.
3. The model was opened, from which, a 5 mm thick of oil layer was removed and replaced with a packed 5 mm thick of water layer. The model was then closed tightly with all lines connected, and put, upside down, in a high pressure container.
4. Steam was injected into the model at a designed rate and the oil and water produced from the outlet (producer) were measured. The temperature distribution at certain times was also recorded.
5. The residual oil saturations in the model were measured after steam injection.

DISCUSSION OF THE EXPERIMENTAL RESULTS

Mechanisms of Horizontal Fracture-Assisted Steamflooding Super Heavy Oil

The mechanisms of conventional steamflooding heavy oil are well known through the publications of laboratory and field test results. The viscosity reduction with the increasing temperature in the heavy oil is the main reason. The distillation and extraction by steam also play certain roles recovering light oils. When reservoir temperature increases, the oil and water volumes expand, and rock porosity decreases. These result in the decrease of irreducible oil saturation, increase of irreducible water saturation, and the change of the rock wettability to water wet. In some unconsolidated and consolidated tar sands reservoirs, the formation compaction certainly helps to further improve oil recovery as well.

A severe problem during conventional horizontal steamflood is the steam override due to gravity segregation in reservoir. This reduces steam volumetric sweep efficiency and decreases oil recovery. However, in the horizontal fracture-assisted steamflood, the gravity segregation moves the injected steam from bottom to top and heats the entire vertical section. Thus, the new process changes the steam segregation from an unfavorable role to a favorable role in flooding heavy oil reservoirs.

In an analysis of the results from experiment 1 (model study) with steam injection rate corresponding to a field rate of 160 m^3/d, the temperature distribution in the vertical cross-section during the time of 0.5, 1.0, 1.5, and 1.75 PV (pore-volume) of steam injected are shown in the Figures 2, 3, 4, and 5 respectively. These indicate:

1. Prior to steam breakthrough, the flowing paths of steam occupied the lower part of formation; and the majority of the initial oil was at the top of formation.
2. The oil above the horizontal fracture was heated rapidly by the overriding steam and heat conduction. Then the hot oil dropped to the lower flow paths and flowed to the producing well.
3. If the top of the oil zone was not hot, the upper part of the initial oil ahead of the steam zone was immobile. At the time, there was no steam fingering problem. When temperature was high enough over there to melt the viscous crude, the downward moving oil would create steam breakthrough quickly in this well.
4. The time of very late steam breakthrough in our model study corresponded to 1.57 PV of steam (equivalent water) injected.

The difference of heating reservoir between conventional steamflood and horizontal fracture-assisted steamflood is shown clearly in Figure 6. In which, the steam's flowing paths of the conventional flood stay at the top of the formation, whereas the

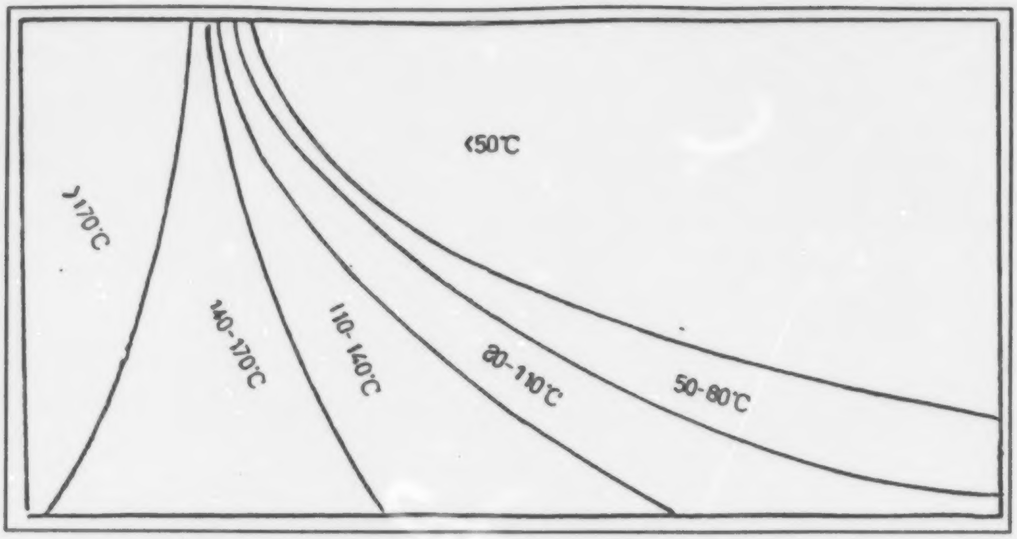


Figure 2. Diagram of cross-section temperature distribution at 0.5 PV.

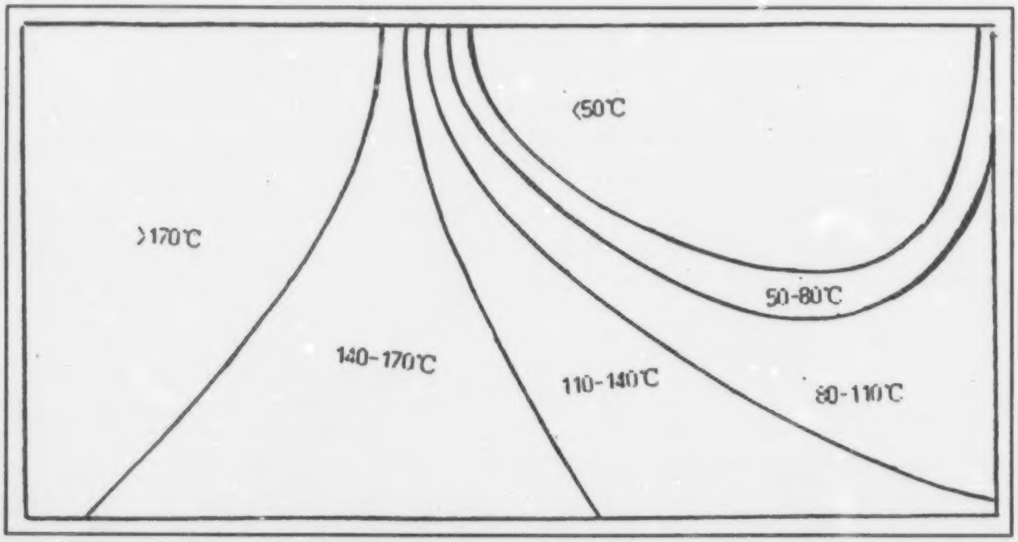


Figure 3. Diagram of cross-section temperature distribution at 1.0 PV.

initial oil exists at the bottom. This therefore results in an early steam breakthrough, and the heating efficiency is much lower than that of the horizontal fracture-assisted steamflood. Accordingly, heating the reservoir by steam should take advantage of steam movement controlled by gravity segregation. In doing so, the position of the steam's flowing paths should be as low as possible in the formation. This could heat the reservoir oil more efficiently and get high oil recovery with higher oil-steam ration. From this analysis, we should also realize that a horizontal well drilled through the lower part of the formation could be used as flowing paths for steamflood, and this technique has great potential especially in steamflooding super heavy oils.

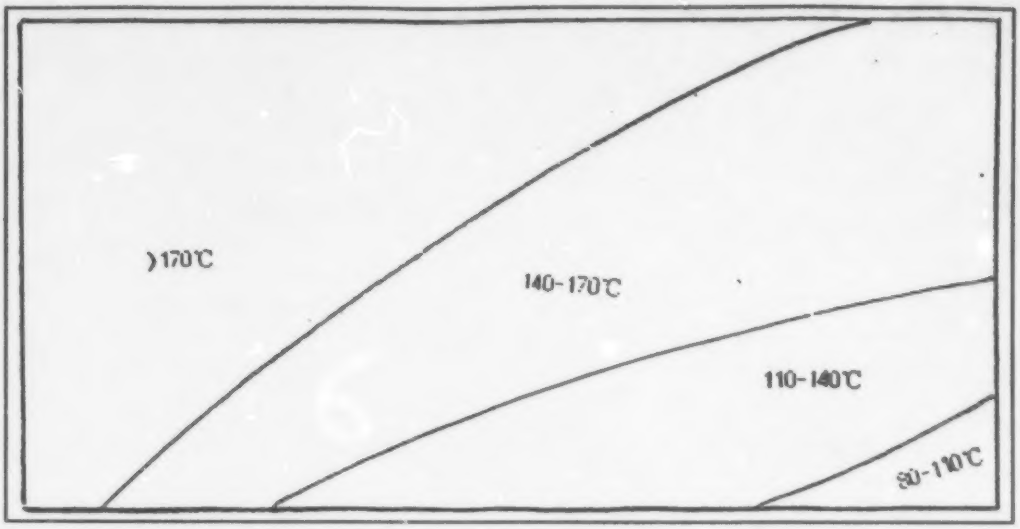


Figure 4. Diagram of cross-section temperature distribution at 1.5 PV.

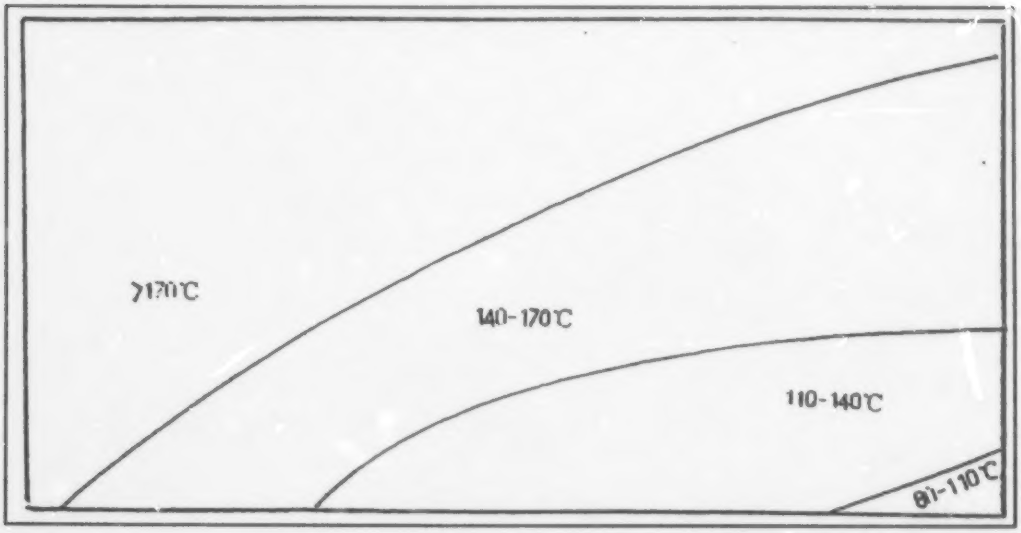
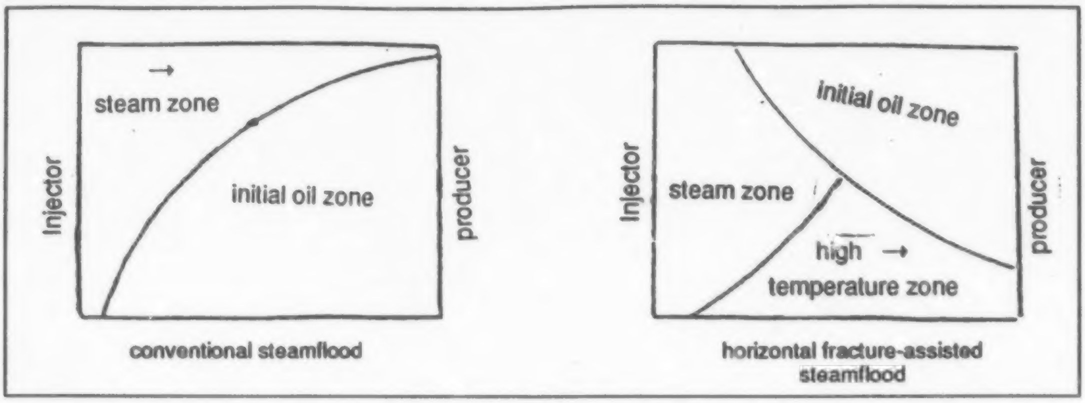


Figure 5. Diagram of cross-section temperature distribution at 1.75 PV.

Influence of Steam Injection Rate to Horizontal Fracture-Assisted Steamflood

It is well known that performance for conventional steamflood is always affected by steam injection rate. We also found from our model studies that input speed of steam had significant influence to the horizontal fracture-assisted steamflood. Table 2 as well as Figures 7 and 8 show the oil production performance at the different steam injection rates. According to these, obviously, the results from 160 tonnes/d. We believe that 160 tonnes/d is an optimum injection rate in our simulation.

The oil recovery at the rate of 120 tonnes/d was almost the same as that at the rate of 160 tonnes/d, but the cumulative oil-steam ration from the former was much less than that from the latter. The reason


→
steam zone
injector
initial oil zone
producer
initial oil zone
injector
steam zone
high →
temperature zone
producer

conventional steamflood

horizontal fracture-assisted steamflood

Figure 6. Comparison of conventional steamflood and horizontal fracture-assisted steamflood.

Table 2.

Number	Injection rate (m^3/d)	Recovery (%)	Cumulative OSR (m^3/m^3)	Project time (d)	Net oil produced (m^3)*
No. 1	160	41.09	0.230	1495	37989.0
No. 2	200	38.47	0.132	1869	20802.9
No. 3	120	40.07	0.184	2243	30635.7

* net oil produced was calculated according to 1 m^3 oil being able to generate 13 m^3 steam

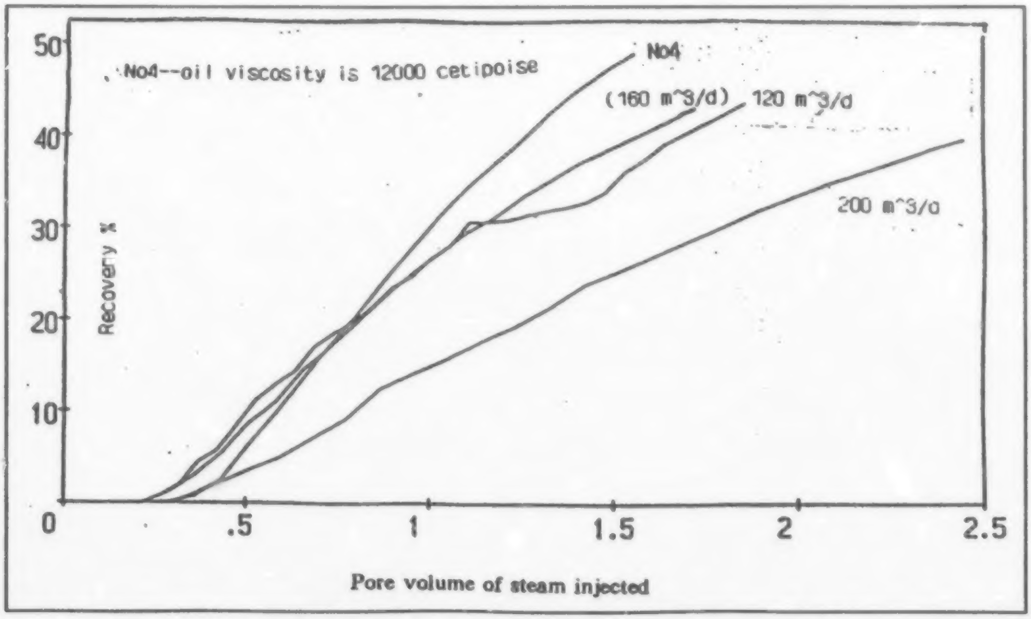


Figure 7. Relationship of recovery with steam amount injected at different injection rate.

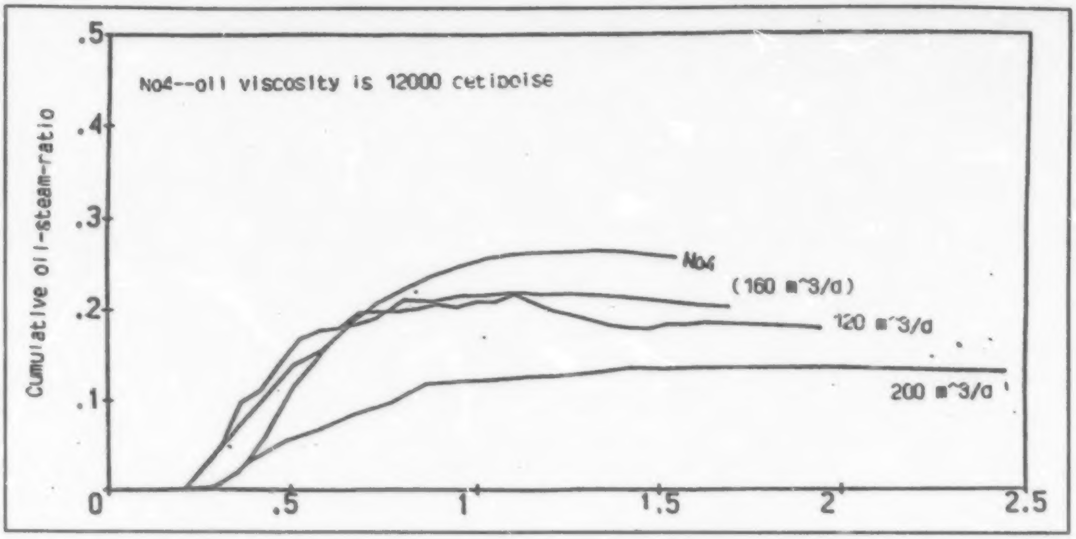


Figure 8. Relationship of oil-steam-ratio with steam amount injected at different injection rate.

for this was the severe heat losses due to steam segregation at low injection rate. On the other hand, the oil-steam ratio from the rate of 200 tonnes/d was the lowest in these three tests. This is because too much heat was lost from the producer and oil resaturation occurred at the lower part of the formation.

Analysis of Residual Oil Saturation

The distribution of residual oil saturation in the model was measured after each test in order to know the displacing and driving mechanisms for super heavy oil recovery by using horizontal fracture-assisted steamflood. The model had 80 grid blocks with 5 layers in vertical direction and 16 areal blocks. Figures 9, 10, and 11 show the residual oil distribution in the vertical section between injector and producer after the tests with steam rates of 160 tonnes/d, 120 tonnes/d, and 200 tonnes/d respectively. From these results, the said distributions were obviously affected by steam injection rates.

Figure 11 presents the vertical distribution of residual oil from a high steam injection rate (200 tonnes/d). IN this case, the oil resaturation might occur near the bottom of the formation, in which, the residual oil saturation was very high. This is because of high steam velocity, the effect of gravity segregation was insignificant. The steam carried plenty of heat from the lower part of formation to the central area and widened the flowing path for more heat flow. Thus the steam broke through from the middle part of the reservoir instead of the top. This can be easily identified by the temperature distribution shown in Figure 12. From this, the low temperature region exists in the structurally low area, indicating the resaturated oil would be difficult flowing to the producer due to its relatively high viscosity as low temperature.

Figure 10 presents the vertical distribution of residual oil from low steam injection rate (120 tonnes/d). In this case, the residual oil saturation in the middle of formation was very high. This is due to the low steam rate with high heat losses resulting in narrow flowing paths for steam and hot water flow, so the oil in central area had no chance to be effectively displaced by steam and hot water.

In our model studies, the test with steam injection at 160 tonnes/d could be an optimum case. The vertical distribution of residual oil is shown in Figure 9, also the areal distribution in the bottom, middle, and top layers are presented in Figures 13, 14, and 15 respectively. From these figures, the following views can be obtained:

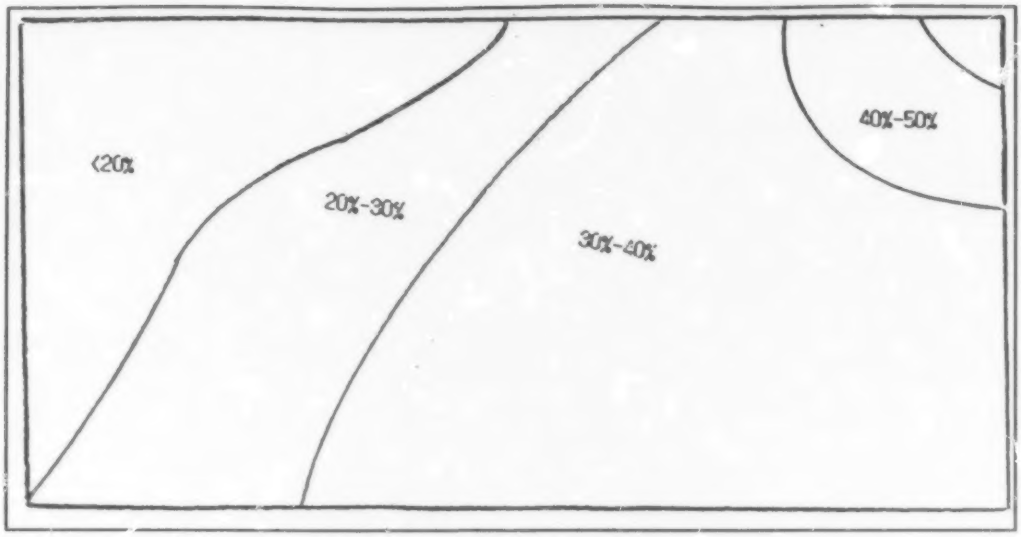


Figure 9. Distribution of residual oil saturation at rate 160 m^3/d.

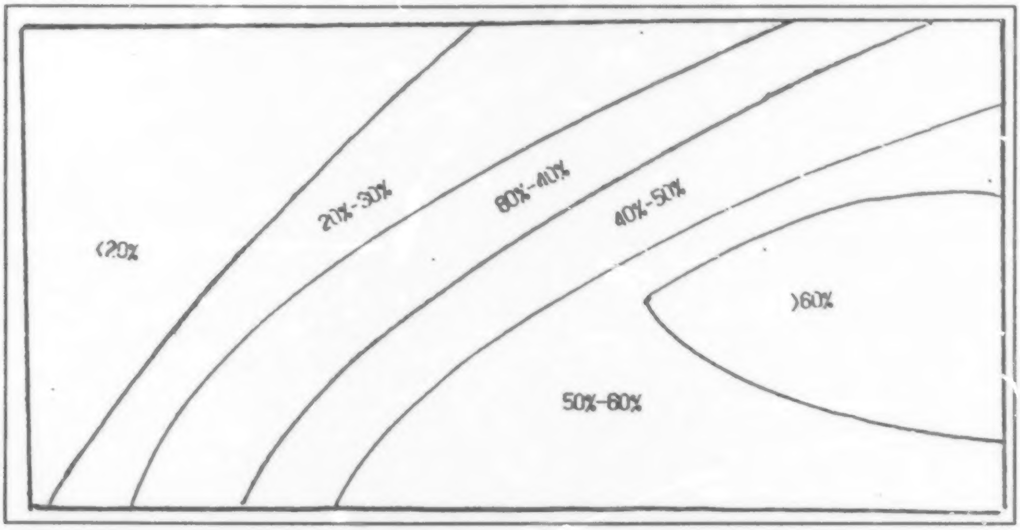


Figure 10. Distribution of residual oil saturation at rate 120 m^3/d.

1. The volumetrically sweep efficiency by steam was almost 100%.
2. The top of the formation was entirely swept by steam, but the further the distance from the line of injector-producer, the thinner the steam zone.
3. The bottom part of the formation was swept by high temperature water.
4. The more the steam and hot water swept, the less the residual oil saturation existed.

Influence of Oil Viscosity to Horizontal Fracture-Assisted Steamflood

The experiment No. 4 studying the influence of oil viscosity to horizontal fracture-assisted steamflood

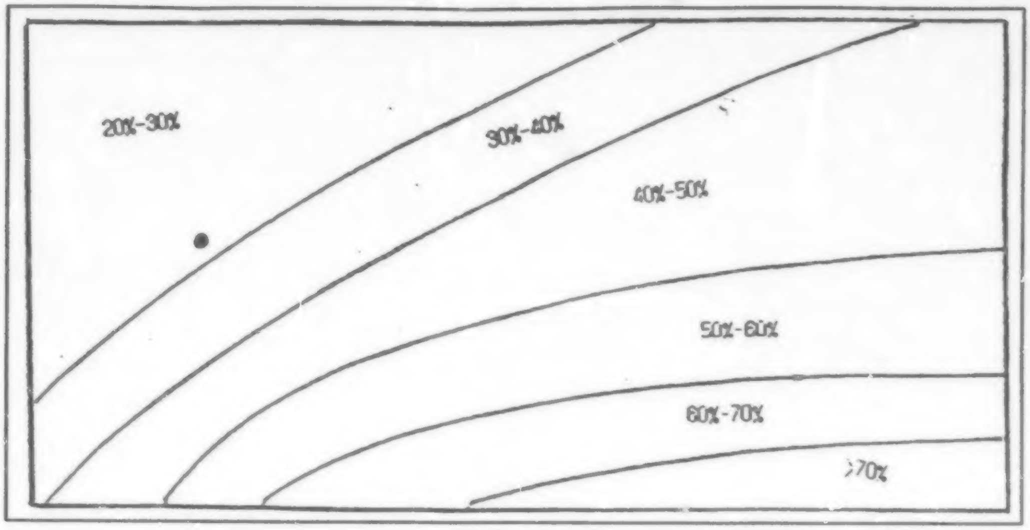


Figure 11. Distribution of residual oil saturation at rate 200 m^3/d.

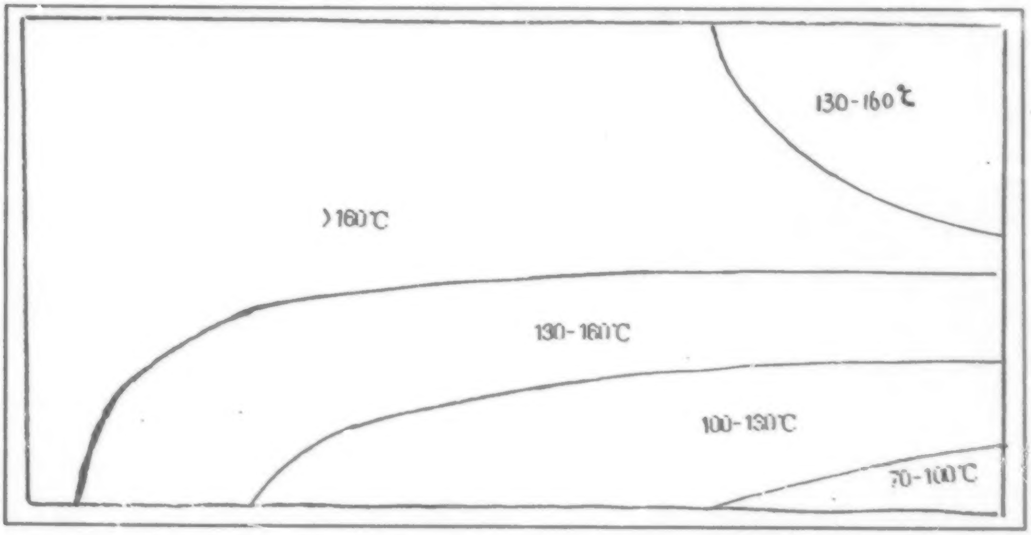


Figure 12. Temperature distribution of steam breakthrough time at 200 m^3/d.

was done by using crude with viscosity of 12,000 cp. The results from the steam injection of 160 tonnes/d was excellent. From Figures 7 and 8, when the volume of steam injected was 1.4 PV (pore volume), the oil recovery and oil-steam ratio were 47.78% and 0.258 respectively. Since the said steam injection was not the best rate for such oil, the steamflood performance at the optimum rate could be much better. Therefore, the horizontal fracture-assisted steamflood can be used not only for super heavy or special heavy oil, but also for conventional heavy oil. The lower the oil viscosity, the better the performance would be.

CONCLUSIONS

1. Horizontal fracture-assisted steamflood could create heat communication paths between steam

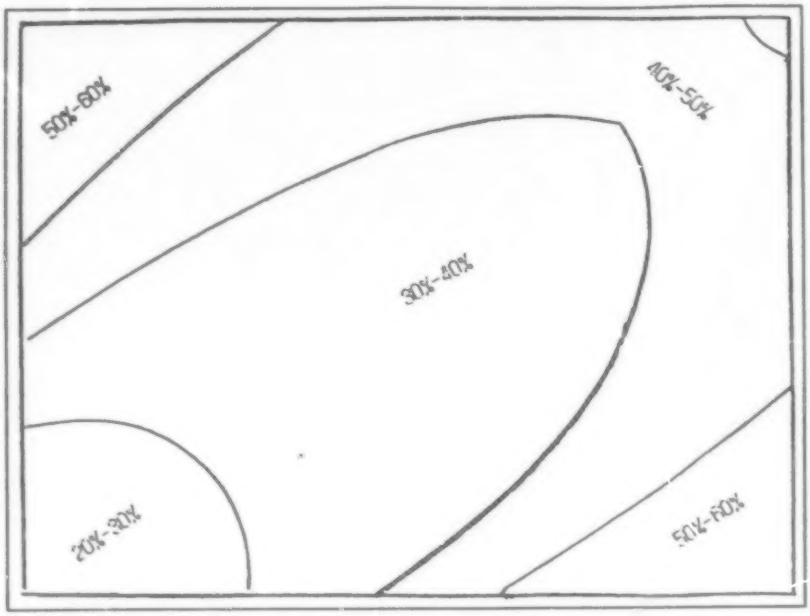


Figure 13. Distribution of residual oil saturation at the top (160 m^3/d).

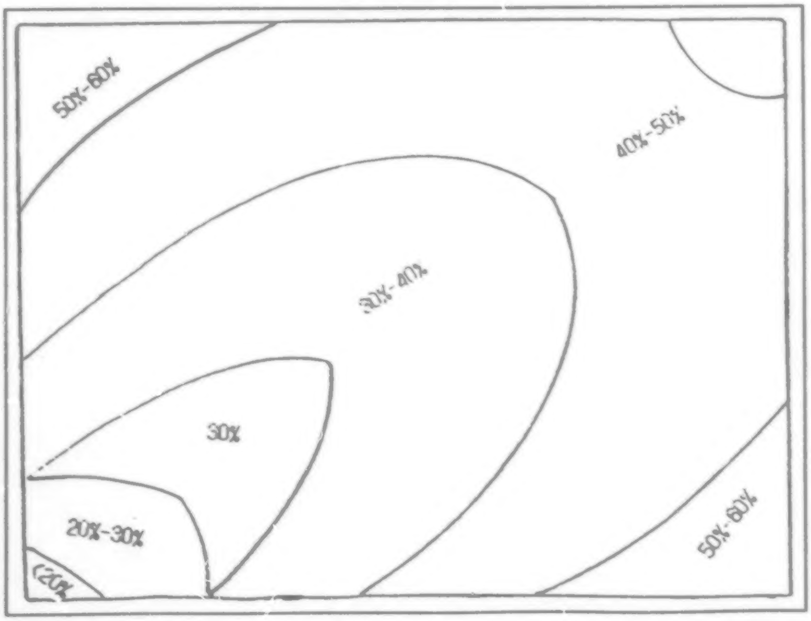


Figure 14. Distribution of residual oil saturation at the middle (160 m^3/d).

injectors and oil producers in the super heavy oil reservoirs.

2. During the mentioned steamflood operation, steam gravity segregation would result in high heating efficiency, oil-steam ration and oil recovery.
3. The performance of horizontal fracture-assisted steamflood was affected by steam injection rates. Which also influenced the distribution of residual oil saturation in the mode.
4. The residual oil saturation at a certain point in the model was in inverse proportion with the amount of steam and hot water injected.
5. The lower the viscosity of oil, the better the performance of horizontal fracture-assisted steamflood.
6. Horizontal wells possess great potential in steamflooding super heavy oil reservoirs.

ACKNOWLEDGEMENTS

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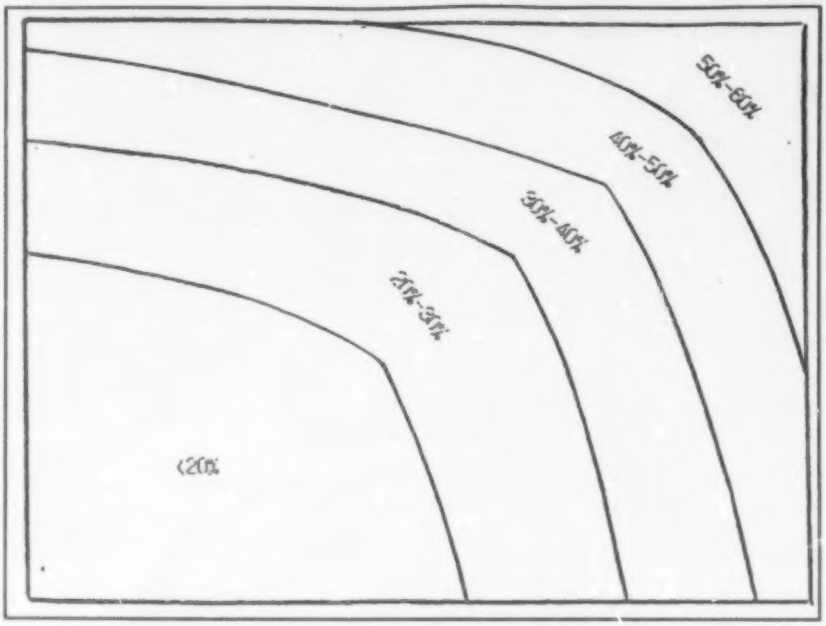

Figure 15. Distribution of residual oil saturation at the bottom (160 m³/d).

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A MECHANICAL ANALYSIS OF BHA BEHAVIOR IN A HORIZONTAL WELL WITH THE METHOD OF WEIGHTED RESIDUALS

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ABSTRACT

An analysis of bottom-hole-assembly (BHA) behavior during horizontal well drilling by using the method of weighted residuals (MWR) is presented in this paper. The computer programs were successfully developed with MWR for the analysis of BHA under large or small deformation in the bottom hole. These programs, with certain advantages of wide range application, high accuracy, simplicity, and speed, can run on microcomputers to simulate the various mechanical behavior in BHA. This paper discusses the non-linear characteristics of BHA under large deformation, and the development of these computer programs for such conditions. It also points out the effect of some important parameters on the behavior of BHA. Furthermore, a new model of rock-bit interaction, and the basic principles of controlling of wellbore trajectory in horizontal drilling are introduced in this article.

INTRODUCTION

When solving many engineering problems, a small deformation is often acceptable in structural analysis. However, this is no longer tolerable in cases with large deformation in the structure, and a new approach is needed in this situation. For instance, a BHA analysis program under small deformation is widely used for wellbore trajectory control in conventional directional drilling with a small build-up rate. Such a program is still useful for long-radius horizontal drilling, but not for those with medium or short radius. In the latter situation, the BHA is already under large bending deformation at the build-up sections. Thus accepting small deformations will result in significant errors in the BHA analysis. In attacking this problem, American engineers have published their solutions with regard to BHA analysis under large deformation by using finite difference method.[2,3] Since non-linear items are involved in differential equations, BHA analysis with large deformation is much more difficult than that using conventional approach. On the basis of a small deformation analysis of static BHA behavior,[1] the authors have studied the large deformation problem of static BHA behavior[4] with the method of weighted residuals.[12]

Firstly, this paper presents the analysis of BHA under small or large deformation by using MWR and their applications. Then, in combination with a new model of rock-bit interaction, this paper discusses the principle and computer programs for wellbore trajectory control in horizontal wells.

THE METHOD OF WEIGHTED RESIDUALS FOR BHA ANALYSIS

The method of weighted residuals is a powerful numerical technique for solving differential equations. This method has the advantages of convenience, accuracy, simplicity in programing, and the residuals of the calculations can be known. Thus MWR has been widely used in structural analysis in recent years. For 2-D and 3-D analyses of the BHA static behavior under large or small deformation, the authors have successfully used this method to tackle the said problems. From which the programs BHAP-1 (to handle small deformation) (Figure 1) and program BHAP-2 (to handle large deformation) were thus developed. These programs can run on a microcomputer to calculate the tilt angle, deflection, and internal forces at any point of a BHA. The

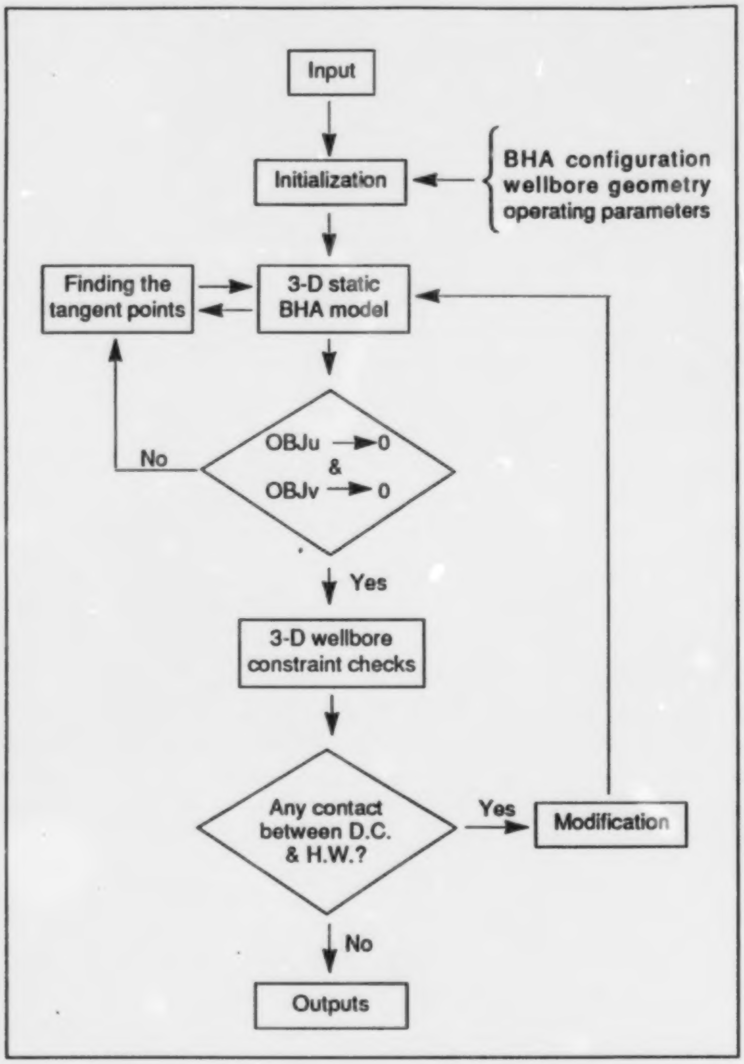

Figure 1. Block diagram for BHA analysis program (BHAP-1).

outputs also include the resultant forces and tilt angle of the bit. In addition, the program BHAP-2 is much simpler than that developed with the finite difference method,[3] and can be easily used in the field.

Non-Linear Effect of BHA Under Large Deformation

The programs BHAP-1 and BHAP-2 were used to compute the behavior of a typical building assembly (BA) in a well with variable hole curvature. The objective of this is to explain the non-linear effect of BHA under large deformation affected by the changing hole curvative. As presented in Figures 2 and 3, the results are shown in two curves in each figure. One stands for the large deformation computations and the other for the small deformation. If the two curves coincide in the graph, this indicates that there is no non-linear effect of large deformation in the BHA behavior. Conversely, the larger the departure of the two curves, the stronger the non-linear effect in the BHA behavior. It can be seen from these theoretical curves that non-linear characteristics of inclination force are strongly affected by both inclination curvature (CH_x) and azimuth curvature (CH_y) (Figures 2a and 3a); but these have a minor effect on the non-linear characteristics of azimuth force (Figures 2b and 3b). In brief, the rise of the non-linear effect of a BHA under large deformation is closely related to the increase of hole curvature. When the hole curvature is smaller than 5 degrees/30 m, the non-linear effect of BHA may be neglected; and the small deformation analysis of BHA can meet the requirement of engineering calculations. On the contrary, if the hole curvature is larger than 5 degrees/30 m, the large deformation analysis on the BHA behavior should be applied. In a summary, the program BHAP-2 should be used for analysis of the build-up section of medium or short radius horizontal wells; but BHAP-1 is only useful for BHA analysis in conventional directional drilling or large-radius horizontal drilling.

Parametric Study

Many parameters would affect the behavior of a BHA including BHA configuration (stiffness and weight of drill collar, as well as numbers, clearance, and location of the stabilizers), wellbore geometry (hole curvature, apparent radius, inclination, and azimuth of the wellbore), forces on BHA (weight and torque on bit, and buoyancy force from drilling fluid), as well as some dynamic parameters (not considered in the static analysis) such as the rotary speed (rpm), friction and so on. The mentioned BHA analysis programs can be used to compute the effects from these parameters except the rotary speed and friction on the BHA behavior.

Effect of weight on bit (WOB). Weight on bit is a controllable and one of the important parameters affecting the BHA behavior. It is important to know its effect on the bit behavior for the trajectory prediction and drilling control. From the 2-D and 3-D BHA analysis, indicating the WOB affects the mechanical characteristics of the following BHAs.

- *Dropping assembly.* The WOB on the mechanical characteristics of a dropping assembly is considerable. In an inclined straight hole, the dropping force and the original walking tendency on bit decrease with the increase of WOB. In a curved hole, the effect of WOB on the changes of inclination and azimuth force depends on the inclination curvature (CH_x) and azimuth curvature (CH_y) respectively. Whether the CH_y is a positive or a negative

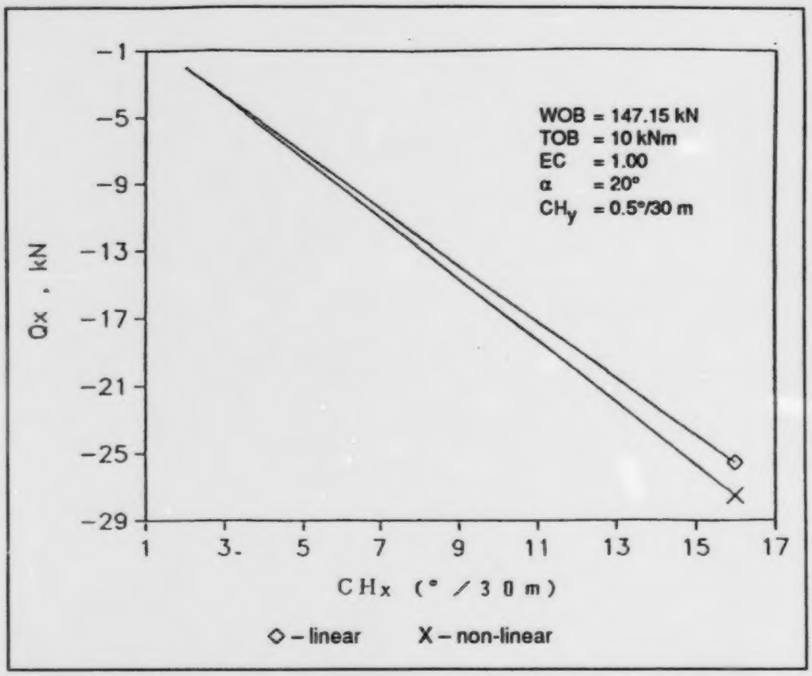

Figure 2a. Effect of inclination curvature on inclination force (BA).

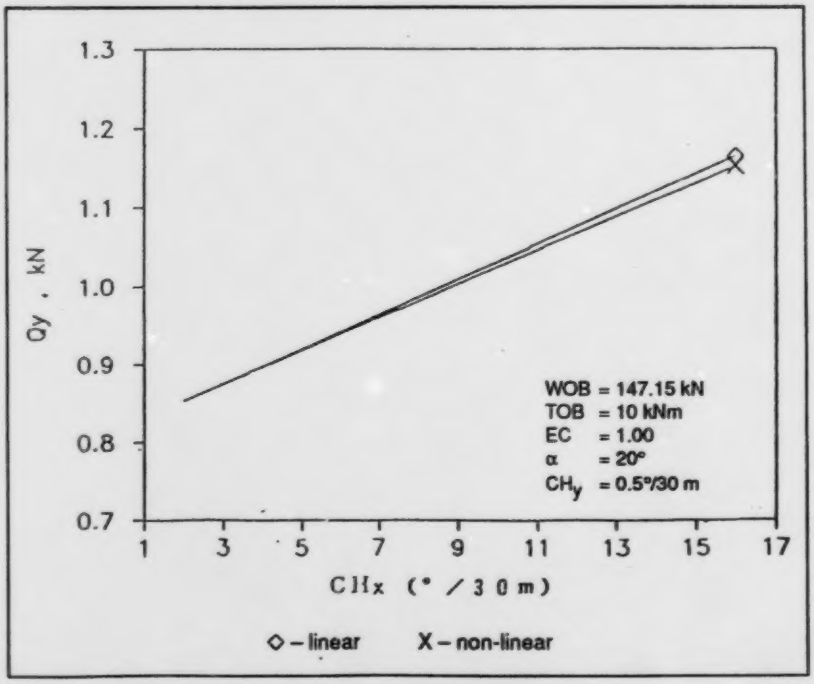

Figure 2b. Effect of inclination curvature on azimuth force (BA).

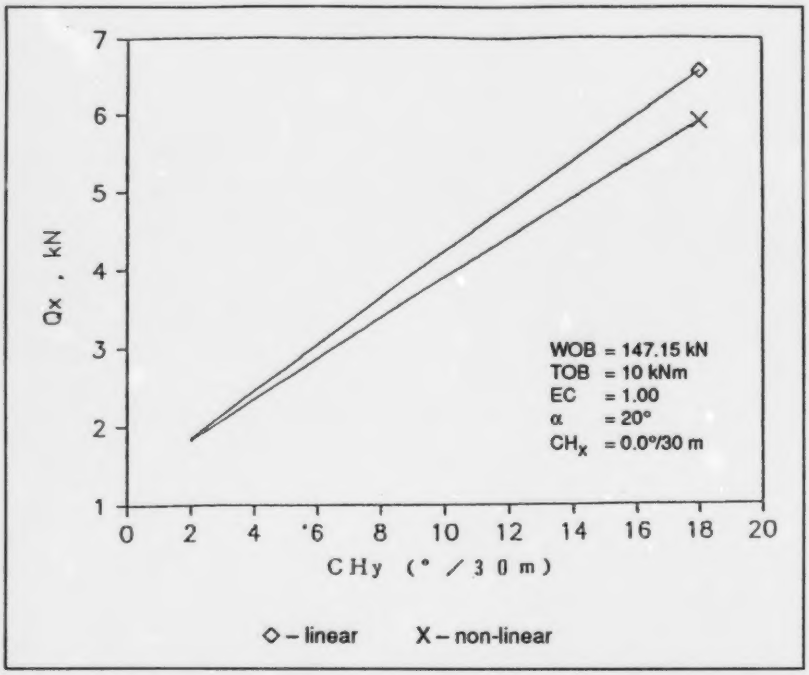

Figure 3a. Effect of azimuth curvature on inclination force (BA).

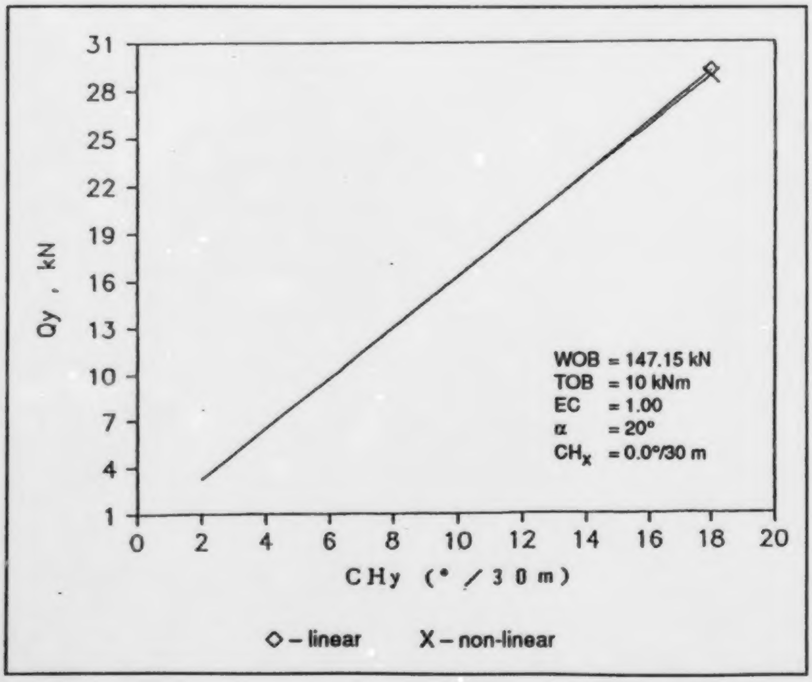

Figure 3b. Effect of azimuth curvature on inclination force (BA).

number, the inclination force affected by the increasing WOB decreases when $CH_x > 0$; and increases when $CH_x < 0$. Whatever the values of CH_y and CH_x are, the original walking tendency increases with the increasing WOB.

- *Building assembly.* The WOB has strong effect on the building assembly. The change of bit behavior with WOB is also related to the wellbore geometry. In an inclined straight hole, the building force on the bit increases with the increasing WOB (it decreases if there is no clearance in hole between the stabilizer and the wellbore); but the original walking tendency decreases with the increasing WOB. In a curved hole and regardless of CH_y values; when $CH_x > 0$ and $CH_x < 0$, the inclination force increases or decreases correspondingly with the increasing WOB. In this case, whatever values CH_y and CH_x are, the original walking tendency decreases only with increasing WOB.
- *Holding assembly.* In an inclined straight hole, WOB has a minor effect on inclination force, but has a considerable influence on azimuth force (increase of WOB can reduce the original walking tendency of the bit). In a curved hole, the WOB has a weak impact on the azimuth force, but has a strong rule on the inclination

force. For instance, an increase of WOB can result in a decrease of inclination force in the borehole with a right walking and building/dropping angle; also can result in an increase of inclination force in the borehole with a left walking and building/dropping angle.

Effect of torque on bit (TOB). TOB is another important factor affecting the bit behavior. Its action complicates the situation for BHA analysis with the deflections in the inclination direction and in the azimuth direction. If there is no TOB in action, the deflections along the two directions will be isolated from each other; thus, the 3-D deformation problem could be solved with the approach of 2-D deformation. Although the TOB has no such dominative role on the inclination force, it does have a significant control on azimuth force for the mentioned three BHAs. TOB is a linear function of WOB[1] when other factors remain constant. These two parameters should therefore be determined simultaneously.

Effect of inclination angle. The laterally distributed load of a BHA comes from the gravity component of drill collars in a deviated well; this load is decided by the inclination angle once the BHA is chosen. At the same time, the density of BHA's longitudinal load also varies with this angle. Since the bending of BHA is related to both the lateral and longitudinal loads, the bit behavior is thus in close relationship with the inclination angle. Our calculations show that the inclination angle strongly affects the inclination forces of the dropping and the building assemblies, but slightly impresses those of the holding assembly. In other aspect, the inclination angle mainly influences the azimuth force of the holding and the building assemblies but slightly sways that of the dropping assembly.

Effect of hole curvature. Various BHAs with elasticity and stiffness will resist the bending deformation when they are put into a curved well. It is shown by calculations that the mechanical responses of BHAs to hole curvature are strong for the holding assembly, moderate for the building assembly, and weak for the dropping assembly. Also because of the coupling effect from TOB, the inclination curvature chiefly affects the inclination force, but impresses the azimuth force to a certain extent as well. Furthermore, the azimuth curvature essentially affects the azimuth force, but has some influence on the inclination force.

Effect of wellbore enlargement. The bending deflection of a BHA is strictly compelled by the wellbore conditions; one of these is the borehole enlargement. When this situation exists, it will influence the BHA behavior. Our study indicates that the effects of borehole enlargement on the behavior of the mentioned BHAs are different, i.e., strong for the holding assembly, moderate for the building assembly, and weak for the dropping assembly. In addition, the effect of the clearance between the stabilizer pads and the wellbore simply cannot be ignored for the analysis of bit behavior. For example, as for the holding assembly with three stabilizers, the bit behavior is affected strongly by the clearance of the stabilizer near the bit, moderately by the middle stabilizer clearance, and weakly by the top stabilizer clearance.

Effect of stabilizer placement. The stabilizer placement on BHA significantly affects well drillings. The so-called "pendulum effect," "lever effect," and "packed-hole effect," are mainly decided by the stabilizer position on the BHA. Our calculations show that the locations of the two stabilizers near the bit have an important effect on the drilling performance; while the locations of the other stabilizers on the BHA do not have the same influence. In general, the locations of stabilizers chiefly affect the inclination force but slightly impress the azimuth force in well drillings.

Buoyancy effect of drilling fluid. The BHA is always affected by buoyancy when it works in a well full of drilling fluid. The results from a previous study[11] indicate that the effect of buoyancy reduces the weight per unit length of BHA in air (W_0), i.e., $W = Kf * W_0$ where W is the weight per unit length of BHA in a well filled with drilling fluid and Kf is a buoyancy correction factor, depending on the densities of drilling fluid and BHA material.

Downhole motor assembly with bent sub. In reference [8], the authors studied an assembly with a 175 mm turbine motor and a bent sub. The results show that the inclination force and azimuth force are significantly affected by the tool face angle (ω) of the assembly. This has been proven by drilling practice. The bent sub angle (ψ) and the distance between the bent sub knee and the bit (L_t) also notably determine the kick-off characteristics of the assembly with downhole motor and bent sub (Figures 4 and 5). An increase in the bent sub angle and a decrease in the distance between the bent sub knee and the bit will increase the kick-off effect. However an increase in the inclination angle would reduce the building effect of the assembly (Figure 6a), but this has nothing to do with the azimuth force (Figure 6b). Using an assembly with a downhole

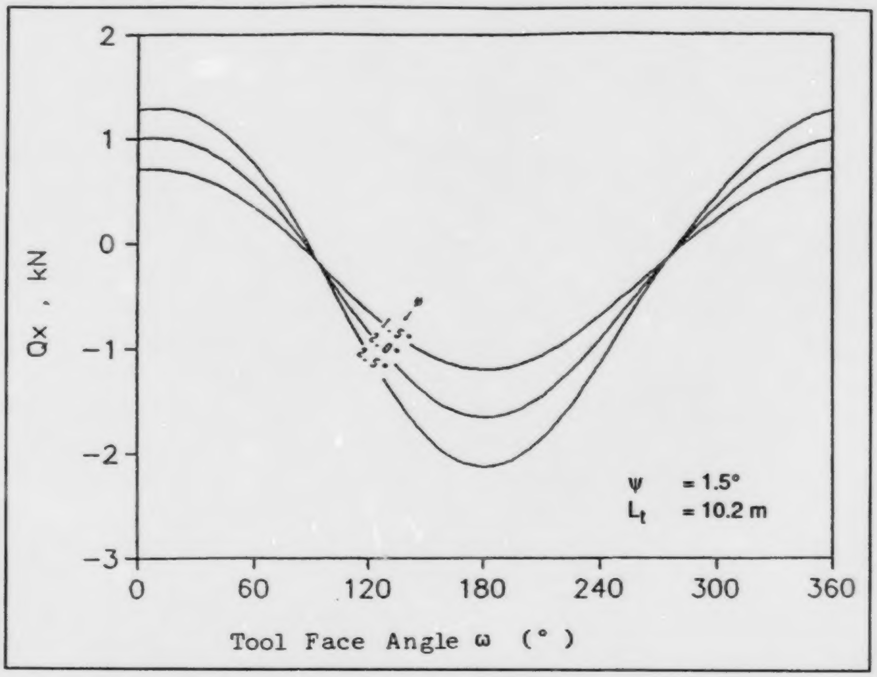

Figure 4a. Effect of ψ and ω on inclination force.

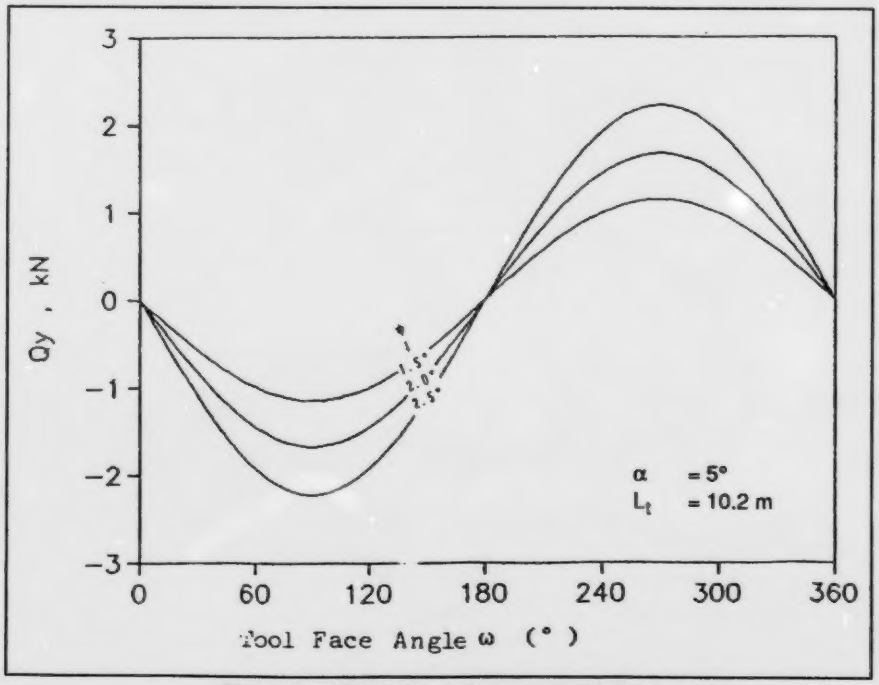

Figure 4b. Effect of ψ and ω on azimuth force.

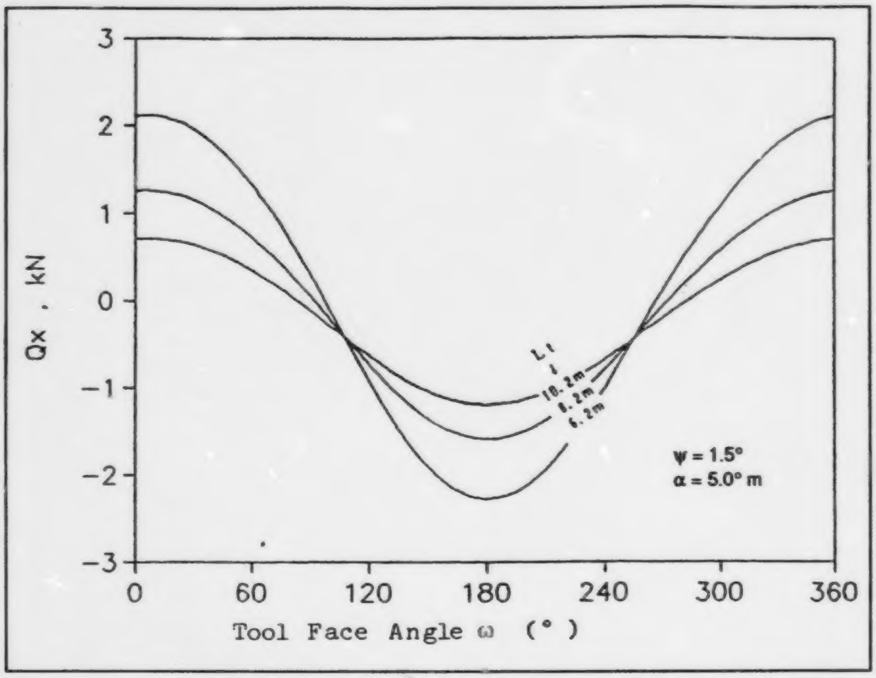

Figure 5a. Effect of L_t and ω on inclination force.

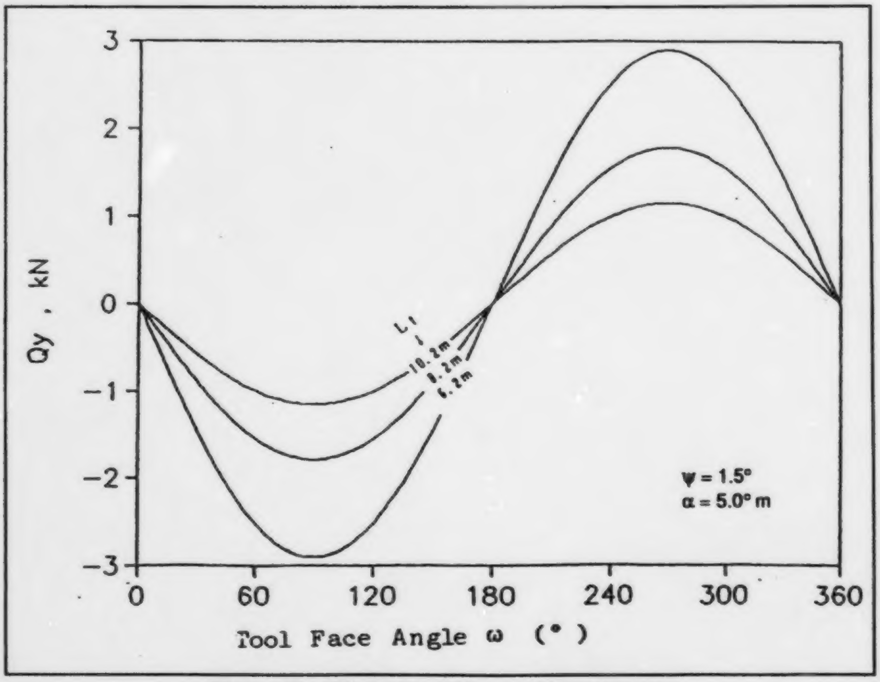

Figure 5b. Effect of L_t and ω on inclination force.

motor and a bent sub for directional well drilling, the trajectory of the wellbore can be controlled effectively by regulating the tool face angle, rationally selecting the bent sub, and using a downhole motor with a proper length.

A NEW MODEL OF ROCK-BIT INTERACTION[6,8]

Rock-bit interaction is a sophisticated key topic in the control theory of the borehole trajectory. However, because of the uncertain properties in the rocks and the complicated drilling mechanisms, it is difficult to establish a generalized model of rock-bit interaction. For convenience, it is assumed that the formation is orthotropic or transversely isotropic; and the bit has different cutting abilities along the bit axial and lateral directions. Based on the published information, the authors formulated a new 3-D, rock-bit interaction model, which accounts for the characteristics of an isotropic drilling action between rocks and bit. A new concept of effective drilling force is also presented in this paper.

The mathematical model of effective drilling force may be expressed as follows:

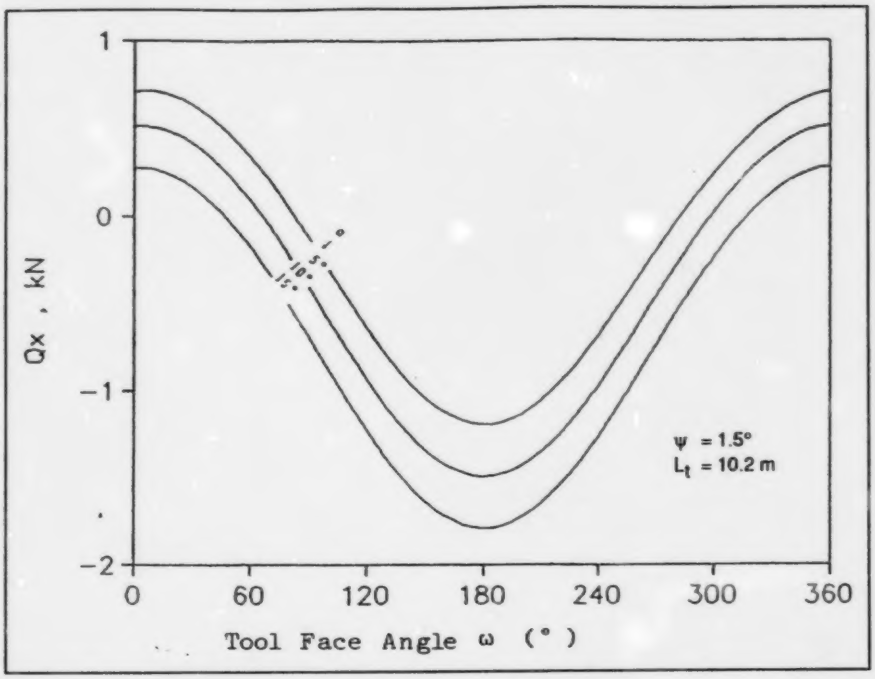

Figure 6a. Effect of α and ω on inclination force.

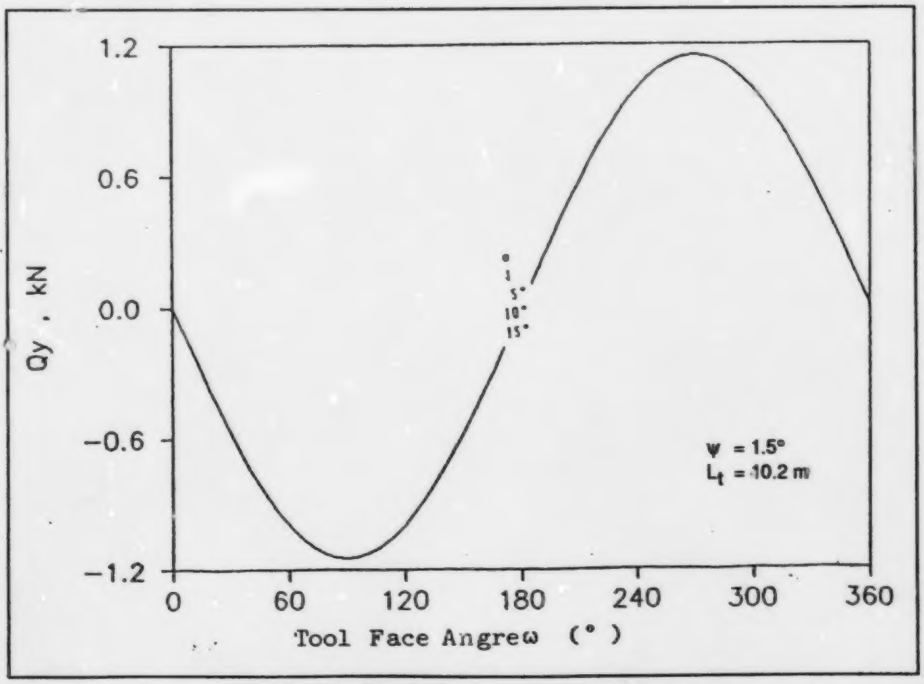

Figure 6b. Effect of α and ω on azimuth force.

$$
\left\{
\begin{aligned}
&\{Q\} = [T]\cdot\{F\}\\
&[T] = I_b I r_1 [E] + I_b\left(1 - I r_1\right)[A] + I r_1\left(1 - I_b\right)[B]\\
&+ I_b\left(1 r_2 - I r_1\right)[C] + \left(1 - I r_1\right)\left(1 - I_b\right)[A][B]\\
&+\left(1 r_2 - I r_1\right)\left(1 - I_b\right)[C][B]\\
&\{F\} = \left[F_x F_y F_z\right]^T
\end{aligned}
\right.
$$

where [E] is an identity matrix of order 3; [A] and [C] are real symmetrical matrices dependent on inclination (α), azimuth (ϕ_o), dip angle (γ), and strike (ϕ_p) of the formation; [B] is a real symmetrical matrix related to the bit tilt angles; I_b is bit anisotropy index; I_{r1} and I_{r2} are formation anisotropy indices; {F} is an array of the bit force; $\{Q\} = [Q_x\ Q_y\ Q_z]^T$ is an array of effective drilling force, in which Q_x and Q_y are inclination force and azimuth force respectively.

Equation (1) relates the bit direction during drilling, formation properties, the borehole geometry, as well as the bit action and its behavior. Thus the effective drilling force may be used as a physical criterion for trajectory prediction and control. The action of {f} is the necessary condition for the existence of {Q} which will vanish when {F} = 0. If the formation and the bit action are all isotropic, [T] in equation (1) is reduced to an identity matrix and {Q} is completely equal to {F}. Equation (1) serves the following purposes:

(a) to determine the bit direction during drilling;

(b) to deduce the anisotropic drilling characteristics of the formation;[9,10]

(c) to deduce the anisotropic drilling characteristics of the bit;[8]

(d) this can be used in combination with BHA analysis in the forward mode to predict the drilling trajectory, etc. and in the inverse mode to evaluate the formation anisotropy, etc.

CONTROL TECHNIQUE OF BOREHOLE TRAJECTORY[7,8]

The control technique of borehole trajectory, including both the hardware (the downhole tools), and the software (computer programs), is an important part in modern well drillings. This technology is theoretically developed based on the BHA analysis and the rock-bit interaction model.

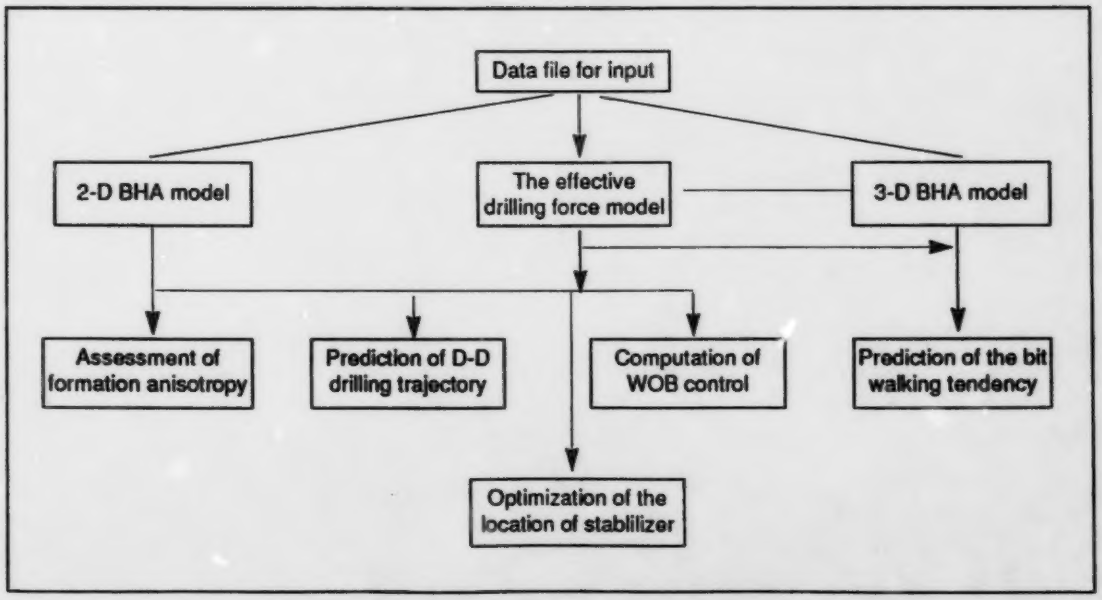
Data file for input
2-D BHA model
The effective drilling force model
3-D BHA model
Assessment of formation anisotropy
Prediction of D-D drilling trajectory
Computation of WOB control
Prediction of the bit walking tendency
Optimization of the location of stablilizer

Figure 7. Principle diagram for multi-purpose programs.

Methodology

The bit deviation in well drillings is the result of: (1) the bit side force and its tilt angle generated by the BHA deformation; (2) the anisotropic drilling characteristics of both the formation and the bit caused by their interaction. Therefore, the leading determinants affecting the drilling direction are classified into five categories as follows:

1. BHA configuration and material properties;
2. bit characteristics;
3. operating parameters (WOB, TOB, RPM, etc.);
4. wellbore geometry (inclination, azimuth, hole diameter and curvature, etc.);
5. formation characteristics.

Factors (1–3) might be subjectively controlled during well drillings. Rock property (5), however, is an unchangeable objective factor. Item (4) is predictive and controllable before drilling and is measurable afterward. Therefore, the established wellbore geometry is not only related to the subjective factors, but also to the objective factors. Such wellbore conditions have a great influence on both BHA behavior and the formation characteristic parameters.[9,10] As previously discussed, the effective drilling force model [equation (1)] can be used to describe the comprehensive effects of the above factors; and the action of this force could be applied as a physical criterion in either forward or inverse computations.

The forward computations are generally carried out for wellbore trajectory prediction and control. For the former, the subjective and objective factors should be known, and the answer is what wellbore geometry will be under these given conditions. For control purposes, the wellbore geometry is planned in advance and the objective factors are also known. Thus the problems are how to select the parameters (BHA, type and material of bit) and how to apply the geological information to achieve our goal.

The inverse computations are used to evaluate the formation characteristics and other unknown parameters. These are normally done after the wells are drilled. From well data, the information about the BHA configuration, the type and size of the bit, the operating parameters, the wellbore geometry, and so on, could be used for this investigation. Accuracy of the inverse computations depends on both reliability of the field data and the design of the inverse model. The author utilized the inverse mode of the rock-bit interaction model[8] for this study.

Because the torque on bit has negligible effect on the bit inclination force,[1,8] a 2-D analysis of BHA without considering torque is accurate enough for the prediction and control computations of inclination. In fact, either the 2-D or 3-D BHA analysis program could be combined with the effective drilling force model (3-D) for engineering application.

Multi-Purpose Microcomputer Programs

Data shown in tables and graphic records could directly help us to identify certain important mechanisms and figure out the relationship between parameters. However there are so many combinations of BHA configuration, operating parameters, wellbore geometry, rock properties, bit, etc., it is impossible to set up tables and figures to predict various responses for the given conditions. Certainly only the computer program is capable of practically solving this problem. According to the preceding methodology, a computer software, based on BHA analysis program and rock-bit interaction model, was developed for wellbore trajectory control. This multipurpose microcomputer program (MPDP-1) was designed by combining the program BHAP-1 with the effective drilling force model. The MPDP-1 is not only useful for trajectory control computations in the conventional directional drillings, but also for the computations in long radius horizontal drillings. The main functions of this program include:

- assessment of formation anisotropy;
- prediction of 2-D drilling trajectory;
- optimization of the location of stabilizer;
- control computation of weight on bit;
- prediction of the bit walking tendency.

The microcomputer program has been used and verified by the field data.[7,8]

In the same way as the development of the MPDP-1 program, we also designed another multi-purpose microcomputer software (MPDP-2) by combining the program BHAP-2 with the effective drilling force model. The MPDP-2, with functions similar to MPDP-1, can be used for studying medium or short radius horizontal drilling. Of course, this program may also be used for the trajectory control in conventional directional or long radius horizontal drilling. It is preferable, however, to use MPDP-1 instead of MPDP-2 for such applications because the computing speed of the former is much faster than that of the latter.

CONCLUSIONS

1. It is feasible to analyze the behavior of a BHA under small or large deformation with MWR, which has the advantages of accuracy, simplicity, and convenience for application.
2. Based on the mathematical models of BHA behavior under small or large deformation, the programs were developed to calculate the deflection, tilt angle, and internal force at any point of a BHA, also to compute simultaneously the resultant force and tilt angle of the bit. These programs can be used easily by field engineers on microcomputers.
3. For a larger deformation, BHA analysis program (BHAP-2) should be used for the computation of BHA behavior in the build-up section of medium to short-radius horizontal wells. In this case, the small deformation BHA analysis programs based on various mathematical approaches should not be used.
4. The results of the parameters study show;
    - the effect of WOB on BHA behavior is related to BHA configurations and borehole geometry;
    - TOB significantly affects the bit azimuth force but affects the bit inclination only slightly;
    - two stabilizers near the bit have a significant effect on the bit behavior, and their placement mainly influences the inclination force but slightly affects the azimuth force;
    - the mechanical response of BHA to the hole curvature, the hole enlargement and the stabilizer clearance are strong for a holding assembly, moderate for a building assembly, and weak for a dropping assembly.
5. When a BHA, with a bent sub and downhole motor is used in directional or horizontal drilling, the wellbore trajectory can be effectively controlled by adjusting the tool-face angle, the bent sub angle and the distance between the bit and the bent knee.
6. The multi-purpose microcomputer program "MPDP-1" is only suitable for the wellbore trajectory control computation in conventional directional drillings or long-radius horizontal drillings, but the program "MPDP-2" could be used for the case in medium or short-radius horizontal drillings.

NOMENCLATURE

α = inclination angle
ϕ_o = azimuth angle
ϕ_f = strike angle of the formation
γ = dip angle of the formation
ψ = bent sub angle
ω = tool-face angle
L_t = distance between the bit and the bent sub knee
CH_x = hole inclination curvature
CH_y = hole azimuth curvature
EC = coefficient of hole enlargement
W = effective weight per unit length of BHA in mud
W_o = weight per unit length of BHA in air
WOB = weight on bit
TOB = torque on bit
W_m = specific gravity of mud (let $W_m = 1.12$)
W_s = specific gravity of drilling string
K_f = buoyancy correction factor
I_r, I_{r1}, I_{r2} = rock anisotropy indices
I_b = bit anisotropy index

OBju, OBjv = objective functions for determining locations of the tangent points

{F} = array of the bit force

{Q} = array of effective drilling force

BHA = bottom hole assembly

BA = building assembly

DA = dropping assembly

HA = holding assembly

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AN ANALYSIS OF DEVELOPMENT RESULTS OF STEAM STIMULATION FOR THREE TYPES OF HEAVY OIL RESERVOIRS IN LIAOHE OILFIELD

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ABSTRACT

Steam stimulation data from three types of sandstone heavy oil reservoirs in the Liaohe oil field are presented in this paper. These pools, located in the western slope of the Liaohe graben where the buried depth is about 700 to 1200 meters, are massive, interbedded, medium-thin to medium-thin thick reservoirs. These not only had a relatively longer developmental history, they also had a similar operation strategy and injection parameters during steam stimulation in this field. From analysis and comparison of field operation results, certain rules for project development could be found, and oil recovery from the mentioned types of reservoirs could be estimated. Some parameters which might affect steam stimulation, such as rock properties, net/gross thickness ratio, reservoir pressure, and oil viscosity, are discussed in this paper.

INTRODUCTION

The distribution of heavy oil in the Liaohe field is concentrated on the western slope belt of the Liaohe graben, starting from the Huanxiling oil field in the south, via Shu-1 district of the Shugung oil field in the middle, and arriving at Gaosheng oil field in the north (Figure 1). In total, there are eight series of strata of heavy oil occurring from the middle-upper Proterozoic to the tertiary, Cenozoic (Figure 1). The burial depth of these reservoirs is 700 to 1200 meters (Huanxiling-Shugung districts), consolidation of sandstone is usually loose, and net pay ranges from 15 to 40 meters. The dead oil viscosity at 50°C is 500 to 20,000 mPa·s, and oil density is commonly 0.930 to 0.975 g/cm^3.

Based on the geologic conditions in these reservoirs, the flood pattern with square-block spacing was developed. The distance between wells is 100 to 167 meters.

Until the end of 1989, steam stimulation of 3061 times was carried out on wells in this field with a total steam injection and oil output being 7.17 million tonnes and 9.43 million tonnes respectively. The oil recovery was 5.5% of OOIP with cumulative oil-steam ratio of 1.3.

Three types of sandstone heavy oil reservoirs in the said field are selected for a comparative analysis of development results. Those reservoirs with depth between 700 to 1200 meters, longer production history, more stimulation cycles, and with a similar steaming technique as well as operation strategy were chosen for this study.

FUNDAMENTAL GEOLOGICAL FEATURES OF THREE TYPES OF HEAVY OIL RESERVOIRS

For reservoir classification, the Dalinghe type of Shu-1-7-5 block is taken to represent the massive reservoirs. The medium-thick interbedded pools are rendered by the Yu-1 and Xing-1 formations of Jin-45 block in Huanxiling oil field. And the prototype of the thin-medium interbedded case is Dujiatai reservoir of Du-66 block in Shu-1 district. The basic geological features in these reservoirs are as follows.

The structure features of Dalinghe reservoir of Shu-1-7-5 block is characterized by a faulted nose dipping to a NW-SE directions with a buried depth of 950 to 1090 meters. The net pay of all zones ranges between 60 to 70 meters, and its average is 41.2 meters. The single layer with thickness more than 10

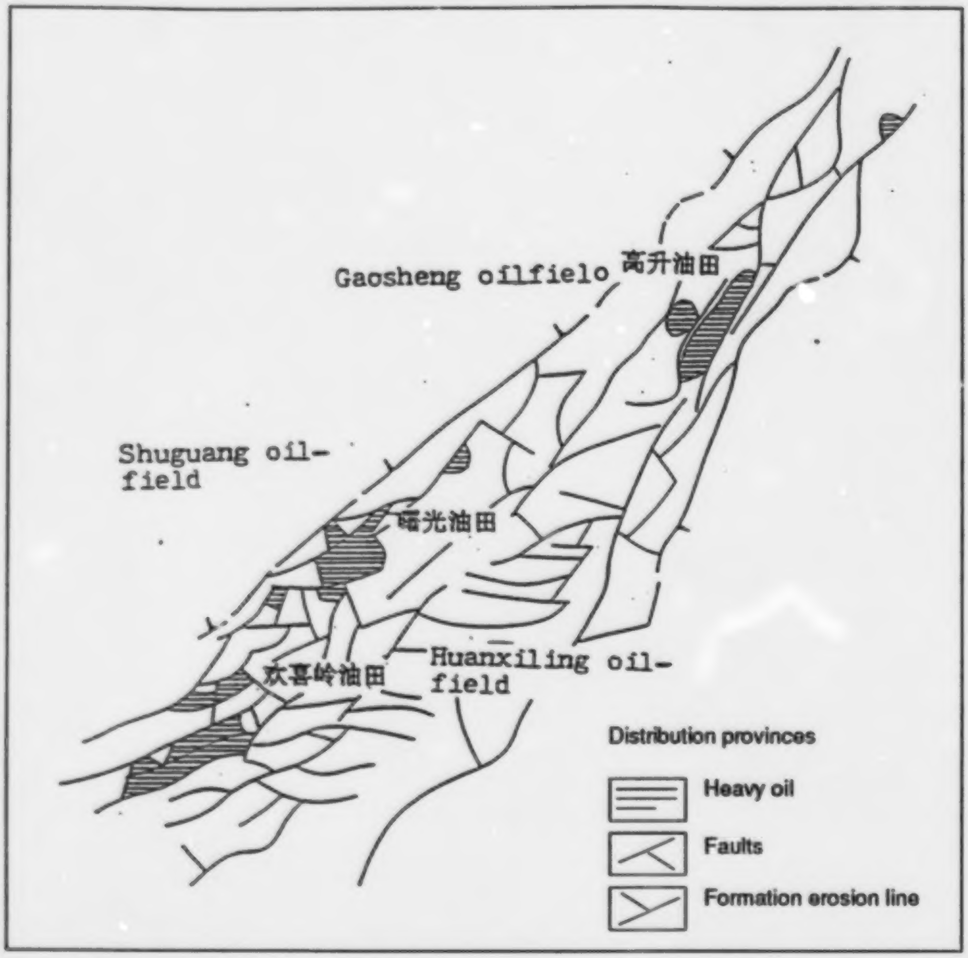


Figure 1. Sketch of heavy oil distribution in the west trough in the Liaohe graben.

meters is about 90% of the total thickness, and the net to gross thickness ratio is 0.73. Basically, the reservoir rock is medium to coarse sandstone suggesting a deep water turbidite deposit. In this reservoir, the average porosity and permeability are respectively 25.6% and 1 to 2 μm^2, also the initial reservoir pressure was 10.4 MPa and temperature at the middle depth is 55.5°C. Regarding oil properties, its density is 0.975 g/cm^3, and the degassed oil viscosity at 50°C is 27,493 mPa·s. The said reservoir with oil-water contact of 1090 meters and water to oil-zone volume ratio of 8.5 is supported by certain amount of bottom water drive in this field (Table 1).

The structure features of both the Yu-1 and Xing-1 formations in Jin-45 block are characterized by a faulted nose slopes plunging towards a NW-SE direction. The buried depth is 820–1060 meters for Yu-1 and 980–1145 meters for Xing-1, and the gross pay is 60–80 meters for the former and less than 50 meters for the latter. The productive zones are in the medium-thick interbedded reservoirs with average net pay of 18.8 and 13.2 meters respectively for the mentioned two formations. The single layer with thickness more than 5 meters is more than 60% of the total thickness, and the net to gross thickness ratio is 0.498 and 0.538 for the said formations respectively. From a geological point of view, these two horizons equally belong to lake-basin deltaic deposit, mainly as

Table 1. Basic geologic parameters for three types of heavy oil reservoirs

Du-66 Block		Jin-45 Block		Shu-1-7-5 Block	Name of fault block
Dujiatai Lower Zone	Dujiatai Upper Zone	Xing-1 Formation	Yu-1 Formation	Dalinghe Reservoir	Series of strata
Thin-medium interbedded reservoir	Thin-medium interbedded reservoir	Medium-thick interbedded reservoir	Medium-thick interbedded reservoir	Massive reservoir	Type of reservoir
900–1200	875–1150	980–1145	820–1060	950–1090	Buried depth of reservoir m,
60–80	60–80	40–50	60–80	60–70	Oil-bearing well interval, m
17.4	26.4	13.2	18.8	41.2	Average net thickness, m
35.6	44.2	53.8	49.8	73.4	Net-to-gross ratio, %
<5	<5	5–10	5–10	>10	Single stratum net thickness, m
>60	>60	>60	>60	>90	Single stratum thickness/gross thickness, %

tributary stream channel and river-mouth sandbar facies. The temperature at the middle depth of each reservoirs is 14.6°C and 50°C and the original reservoir pressure was 9.5 and 11.0 MPa respectively. Regarding average rock and oil properties, these are listed as follows;

		Yu-1	Xing-1
Porosity	%	32.1	29.7
Permeability	μm^2	1.5	1.6
Oil density	g/cm^3	0.993	0.962
Dead oil viscosity	(mPa·s, 50°C)	7 696	486

The oil-water interface was 1020 and 1120 meters respectively in the said reservoirs, giving a certain amount of edge water drive for oil production (Table 1).

The structural appearance of Dujiatal reservoir in Du-66 block exhibits a faulted nose formation on the slope background. The reservoir is buried at the depth of 875 to 1200 meters with gross pay in the upper and lower strata being usually 60 to 80 meters. The oil zones are thin-medium sand-shale interbedded, and the average net pay of the two strata is 26.4 and 17.4 meters respectively. The single layer with net pay more than 25 meters is 43.4% of the total, and that with a net pay less than 2 meters covers about 27.2%. The reservoir rock is mainly medium-grained sandstone-silt with net to gross pay ratio of 0.442 and 0.356 in the mentioned two zones. For these, the average porosity is 18.9–14.9%, and permeability is 0.882–0.615 μm^2 obtained from log interpretation. The initial reservoir pressure was 9.39–11.38 MPa, and the temperature at the middle depth of the pool is 51.2–63.5°C. The oil density is 0.930–0.888 g/cm^3, and dead oil viscosity at 50°C is 300–2000 mPa·s. In these reservoirs, the oil-water contact was respectively 1187.6–1240.4 meters, and edge-water drive is not active (Table 1).

ANALYSIS OF DEVELOPMENTAL RESULTS

For analysis of the results of heavy oil steam stimulation, the criteria of choosing wells for this purpose are:

- Well must have one complete production cycle with a producing period for more than 100 days.
- All the wells stimulated in the second cycle are

included in the first cycle, and those wells in third cycle are in the second second cycle, etc.

- Steam injection on these wells are similar, i.e., injection strength was 70 to 120 tonnes/meter, wellhead steam quality was 60 to 70%, and injection time was more than 90%.
- Wells with or without water cut are not further divided for analysis.

Based on these, the following observations were obtained through the review of production data from the mentioned three types of heavy oil reservoirs.

Steam stimulation performance from reservoirs. From Table 2 and Figure 3, the following conclusions can be made — the constant percentage decline of oil production rates exhibited in steam stimulation wells.

A comparison of the first three cycles production performance (early production rate, average daily oil rate, cumulative oil and cumulative oil-steam ratio) ranks the said reservoirs as follows:

Reservoir	Cumulative oil tonnes	Cumulative oil-steam ratio
Xing-1, Jin-45	20,055	2.59
Dalinghe, Shu-1-7-5	18,750	1.69
Yu-1, Jin-45	12,599	1.61
Dujiatai, Du-66	944	1.30

In view of the oil rate decline in the first two cycles, the fast decrease of 25 to 45% occurred in Xing-1 and Dujiatai reservoirs, whereas Dalinghe and Yu-1 had only a 4 to 5% decline. During cycles 2 and 3, however, Xing was still leading in rate decline of greater than 40%, but others exhibited 20 to 25% oil production decrease.

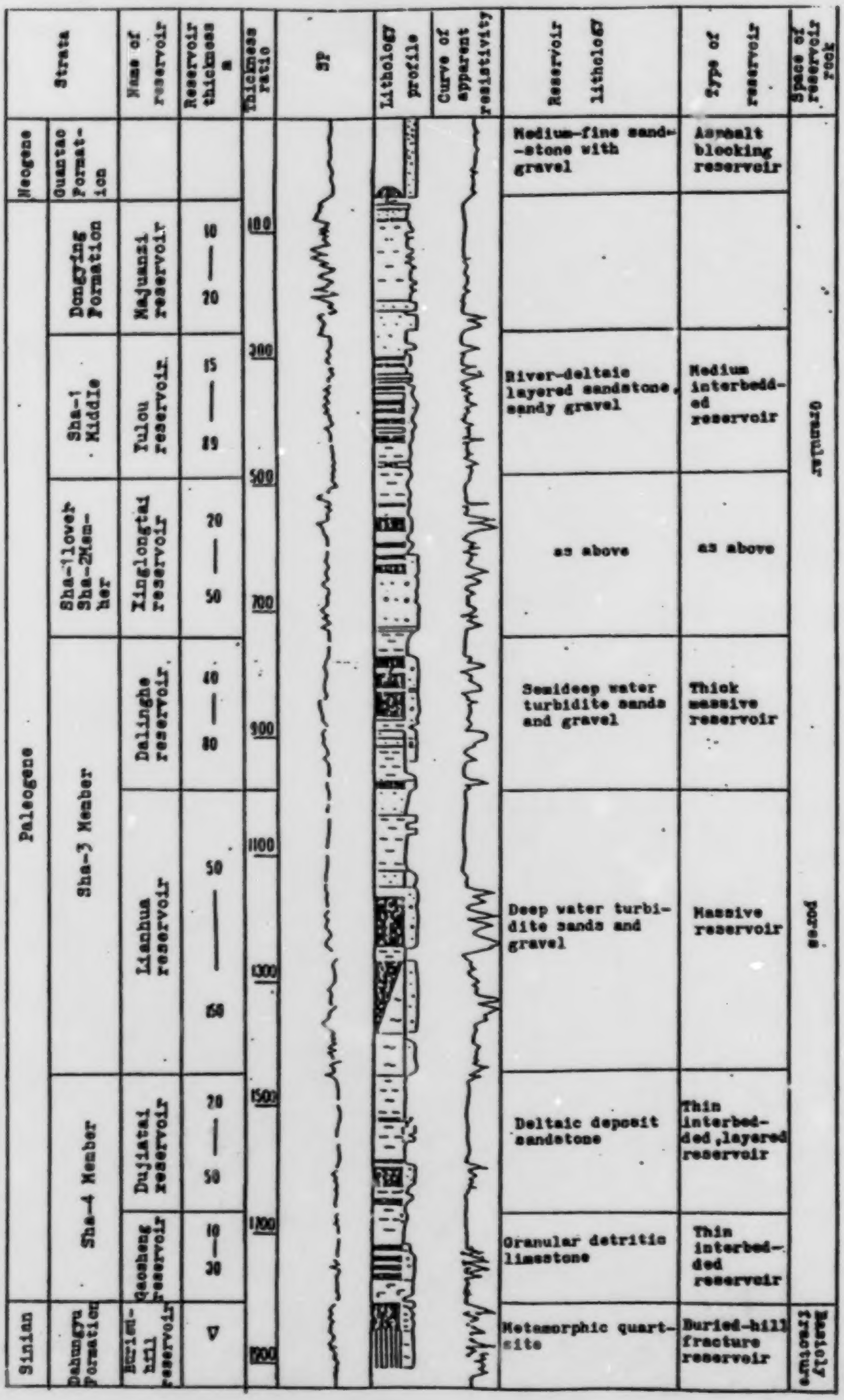
Production from different stimulation cycles. According to the number of stimulated wells in the four series of strata and in three blocks, there were 223 wells in the first cycle, 141 wells in the second, 86 wells in the third, and only 5 wells in the fourth cycle. This indicates that stimulation results were getting poor with the increase of stimulation cycles. Such facts can be found in Table 2 and Figure 4.

- Production period of each cycle was shortened in each turn.
- Early oil production, average daily rate, and cumulative oil decreased cycle by cycle.
- Oil-steam ratio of each cycle declined in each turn.

Water-cut performance in steam stimulation wells. After steam injection, oil wells were shut in for a certain period for soaking. They were then opened for production. Initially, large amount of hot water would be produced due to the lack of dispersed

Table 2. Basic geologic parameters for three types of heavy oil reservoirs

Du-66 Block		Jin-45 Block		Shu-1-7-5 Block	Name of fault block	
Dujiatai Lower Zone	**Dujiatai Upper Zone**	**Xing-1 Formation**	**Yu-1 Formation**	**Dalinghe Reservoir**	**Series of strata**	
1.5:1	1.5:1	2:1–2:3	2:1–2:3	>15:1	Sand-shale ratio, %	
14.9	18.9	29.7	32.4	25.6	Porosity, %	Rock properties
0.615	0.882	1.6	1.5	1–2	Permeability, μm^2	
0.888	0.930	0.962	0.993	0.975	Density, g/cm^3	Fluid properties
300–700	300–2000	486	7696	27,439	Oil viscosity at 50°C, mPa·s	
Heavy oil	Heavy oil	Heavy oil	Heavy oil	Extra heavy oil		
1163.2–1303.0	1187.2–1240.4	1120	1020	1090	Oil-water contact, m	



Strata		Name of reservoir	Reservoir thickness m	Reservoir lithology	Type of reservoir	Space of reservoir rock
Neogene	Guantao Formation			Medium-fine sand-stone with gravel	Asphalt blocking reservoir	Granular pores
Paleogene	Dongying Formation	Majuanzi reservoir	10 — 20			
	Sha-1 Middle	Yulou reservoir	15 — 89	River-deltaic layered sandstone, sandy gravel	Medium interbedded reservoir	
	Sha-1lower Sha-2Member	Xinglongtai reservoir	20 — 50	as above	as above	
	Sha-3 Member	Dalinghe reservoir	40 — 80	Semideep water turbidite sands and gravel	Thick massive reservoir	
		Lianhua reservoir	50 — 150	Deep water turbidite sands and gravel	Massive reservoir	
	Sha-4 Member	Dujiatai reservoir	20 — 50	Deltaic deposit sandstone	Thin interbedded, layered reservoir	
		Gaosheng reservoir	10 — 30	Granular detritic limestone	Thin interbedded reservoir	
Sinian	Dahungyu Formation	Buried-hill reservoir	∇	Metamorphic quartzite	Buried-hill fracture reservoir	Mainly fracture

Figure 2. Combined columnar section of heavy oil in the west trough in Liaohe basin.

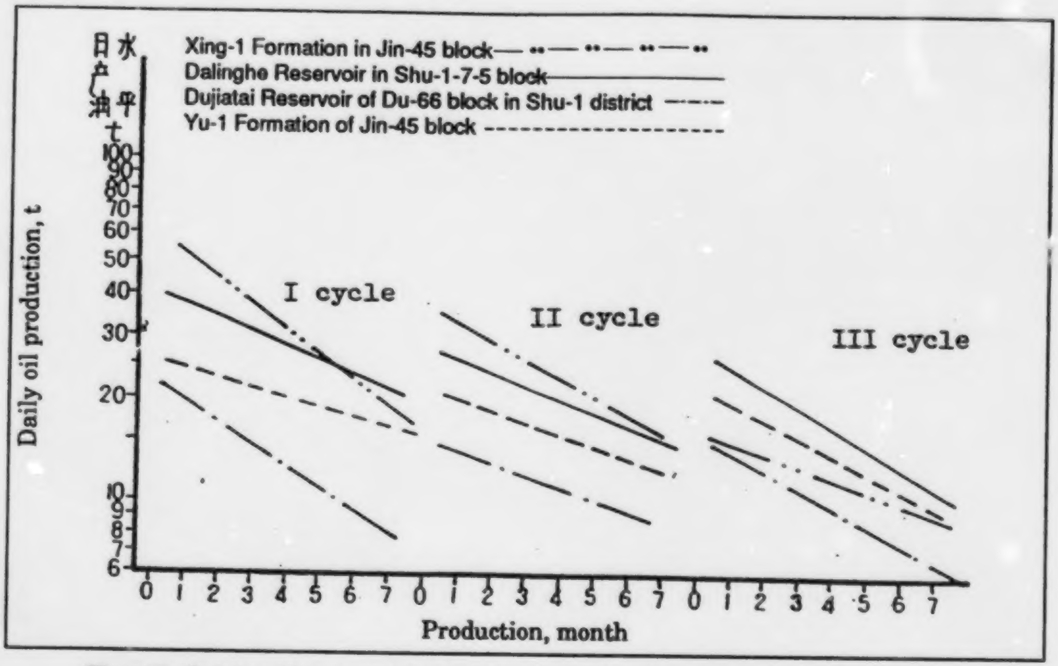


Figure 3. Relationship curves of daily production level vs. time of all cycles in typical blocks.

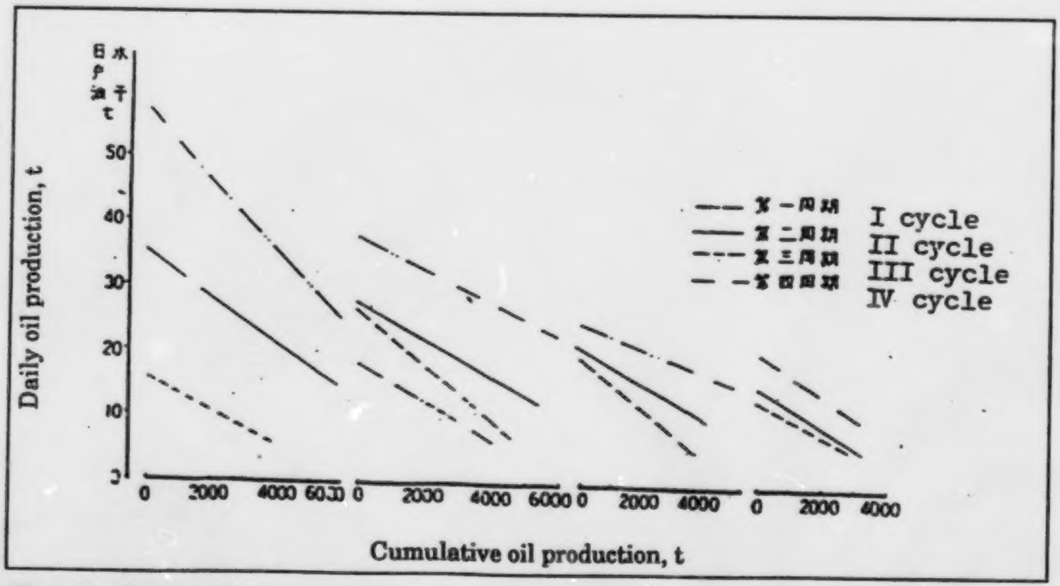


Figure 4. Relationship curves of daily oil production vs. cumulative oil production of all cycles in typical blocks.

residual pressure and temperature in the vicinity of the wellbore, and the nearby liquid with steam was driven downhole and produced. Thus, water cut on wells was high at the beginning and then flattened with the increase of oil output. In general, there were two cases of water cut changes in oil wells as shown in Figure 5.

In the wells without edge and bottom water drive, the initial water cut was high, but progressively decreased to nothing. The typical case with this kind of water cut history was experienced in well 37-35 of Shu-1 district.

In the wells with influence of edge and bottom water drive, water cut at the beginning was relatively high, but quickly dropped to a certain level and then stabilized. Because of the influx of aquifer water, water cut would rise again. This situation can be found in well 19-162 of Jin-45 block.

Forecasts of oil recovery produced by steam stimulation. The dynamic methods including pressure drawdown as well as cyclic production decline, and numerical simulation were utilized for predicting oil recovery by steam stimulation. The results are summarized as follows (Table 3):

- Oil recovery in the Dalinghe massive reservoir of Shu 1-7-5 block is about 24% of OOIP.
- Oil recovery in the Yu-1 formation, medium-thick interbedded reservoir of Jin-45 block is approximately 15% of OOIP.
- Oil recovery in the medium-thick interbedded reservoir of Xing-1 formation in Jin-45 block is around 22% of OOIP. Oil recovery in the Dujiatai thin-medium interbedded pool in Du-66 block is roughly 10% of OOIP.

ANALYSIS OF MAIN GEOLOGICAL FACTORS INFLUENCING STEAM STIMULATION

Reservoir Pressure

Steam stimulation for oil production utilizes heat to lower oil viscosity and to increase mobility of the

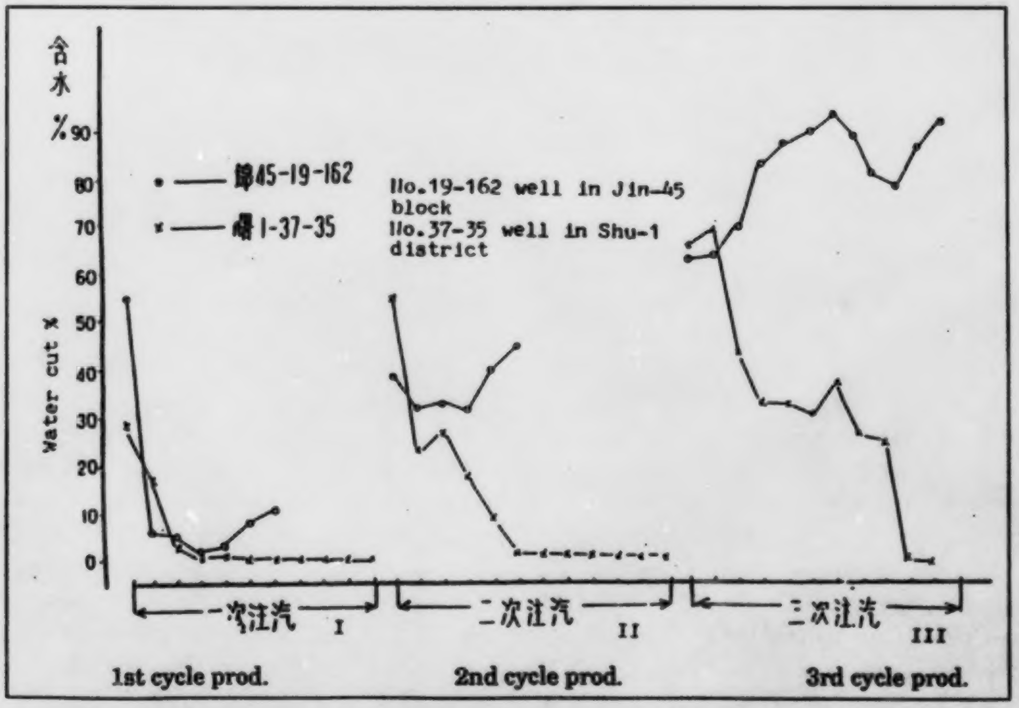


Figure 5. Water cut changes of No. 19-162 well in Jin-45 block and No. 37-35 well in Shu-1 district.

Table 3. Summary of recovery forecast in steam stimulation for heavy oil blocks

Du-66 Block	Jin-45 Block		Shu-1-7-5 Block	Name of fault block	
Dujiatai Zone	Xing-1 Formation	Yu-1 Formation	Dalinghe Reservoir	Series of strata	
Thin-medium interbedded reservoir	As above	Medium-thick interbedded reservoir	Massive reservoir	Type of reservoir	
3136	1025	2475	453	Reserve used, 10^4 t	
3.10	11.28	3.67	14.59	Current oil recovery, %	
10.38	13.00	15.19	22.01	Pressure drawdown method	Recovery %
12.10	17.80	14.50	26.00	Production decline method	
10.35	22.00	15.00	24.00	Numerical simulation	

Table 4. Reservoir pressure and stimulation performance

Time, year	Average formation pressure MPa	Average single-well steam injection, t	Oil production, t	Oil-steam ratio, t/t
85	10.43	2002	11,600	5.80
86	10.25	2229	9500	4.26
87	8.83	2200	2600	1.18
88	5.39	2998	2001	0.67

in-situ oil, thus, more oil is produced, and less reservoir pressure remains. Production data from three types of heavy oil reservoirs illustrates that reservoir pressure directly influences the results of steam stimulation, i.e., higher reservoir pressure, better stimulation performance. For example, fault Jin-90 is a fourth grade block within the Jin-45, where the reservoir of Xing-1 formation is well developed with a net pay of 24.9 meters and with good permeability. After starting production in June 1985, more steaming cycles produced more oil, subsequently the reservoir pressure was gradually depleted, and stimulation performance became poor (Table 1). This situation is also experienced in other heavy oil reservoirs with the same relationship between oil production and reservoir pressure.

Reservoir Physical Properties

These are the important factors influencing the results of steam stimulation. As shown in Table 2, oil viscosities in Xing-1 pool and in Dujiatai lower zone are almost at the same level being 486 and 300–700 mPa·s respectively. Also Table 1 shows the former with a net pay of 13.2 meters and the latter with a net pay of 17.4 meters. However, the steam stimulation results from these are not the same because of the difference in average rock properties in the said formations.

Parameter		Xing-1	Dujiatai lower zone
Porosity	%	29.7	14.9
Permeability	μm²	1.611	0.611
1st cycle production			
Period	days	448	337
Oil rate	tonnes/d	23.3	9.7
Total oil	tonnes	10,416	3,279
Cum. oil/steam ratio		5.16	1.9

Net to Gross Thickness Ratio

For reservoirs under steam stimulation, if most formation and oil properties are nearly the same, then the net to gross thickness ratio could play a certain role in this case. Since high of this value results in small heat losses and would have better stimulation performance. As shown in Table 2, the oil viscosity of the Dalinghe reservoir (Shu-1-7-5 block), and Yu-1 formation reservoir (Jin-45 block) are characterized respectively by extra-heavy and heavy oils. Both of these reservoirs are highly permeable, but net to gross thickness ratio is 0.734 in the Dalinghe pool and 0.498 in the Yu-1 formation. Because of this difference, the average daily oil, total oil, cumulative oil-steam ratio, and oil recovery during stimulation in the Dalinghe reservoir were better than those in the Yu-1 formation (Table 3).

Oil Viscosity

Oil viscosity is one of the important parameters affecting steam stimulation in oil wells. In a comparison of the stimulation performance in Xing-1 and Yu-1 formations, both of them are located in the Jin-45 block with nearly similar rock properties and steaming strategies (Tables 1 and 2), although the perforated intervals of the stimulated wells in Xing-1 pool was thinner than that in Yu-1 reservoir. The stimulation results of the former were better than those of the latter in terms of producing period, daily oil rate and cumulative oil production (Table 5). The reason is that oil viscosity of the Xing-1 crude is much lower than that of the Yu-1 oil. This is not difficult to understand from the relationship between temperature and oil viscosity changes.

Table 5. Comparison of steam stimulation results of Yu-1 and Xing-1 reservoirs in Jin-45 block

Xing-1 Formation	Yu-1 Formation	Series of strata	
12	44	Well number	
22.9/6.1	25.8/8.1	Gross/net thickness, m	
1.6	1.5	Average permeability, μm²	
302	4890	Oil viscosity at 50°C, MPa·s	
68.8	68.7	Steam quality at wellhead, %	
11.4	13.1	Rate of steam injection, t/h	
19870	2144		
54	33	Time, d	Flowing
65.2	50.4	Daily oil, t	
6434.0	3847.0	Cumulative oil for the first cycle, t	

As shown in Table 6, with oil viscosity of 10 mPa·s, the reservoir temperatures of Yu-1 and Xing-1 formations are 214.6°C and 135.3°C respectively. It is obvious from this that the duration of preserving high oil mobility for production is longer in the Xing-1 reservoir rather than in the Yu-1 formation. From Figure 6, the curves of oil rate vs. cumulative oil also demonstrate that production performance in Xing-1 formation was better than that in Yu-1 reservoir.

A numerical model was utilized to compute the effect of oil viscosity on the results of steam stimulation in the Dalinghe reservoir (Shu-1-7-5 block). The outcome is presented in Figure 7; stimulation performance would be degraded with the increase of oil viscosity, regardless of thin or thick reservoirs.

CONCLUSION

1. Based on the current available technologies for thermal recovery of heavy oil in Liaohe field, the better results were obtained from operations in the mentioned types of oil reservoirs at depth of about 700 to 1200 meters.

Table 6. Changes of oil viscosity and temperature of Yu-1 and Xing-1 reservoirs in Jin-45 block

Xing-1 Formation Temperature, °C	Yu-1 Formation Temperature, °C	Series of strata Viscosity, MPa·s
317.8	401	0.534
228.7	328	1.65
165.6	252.7	5.0
135.3	214.6	10
110.5	182.4	20
84.6	147.0	50
69.1	124.9	100
43.2	85.5	500

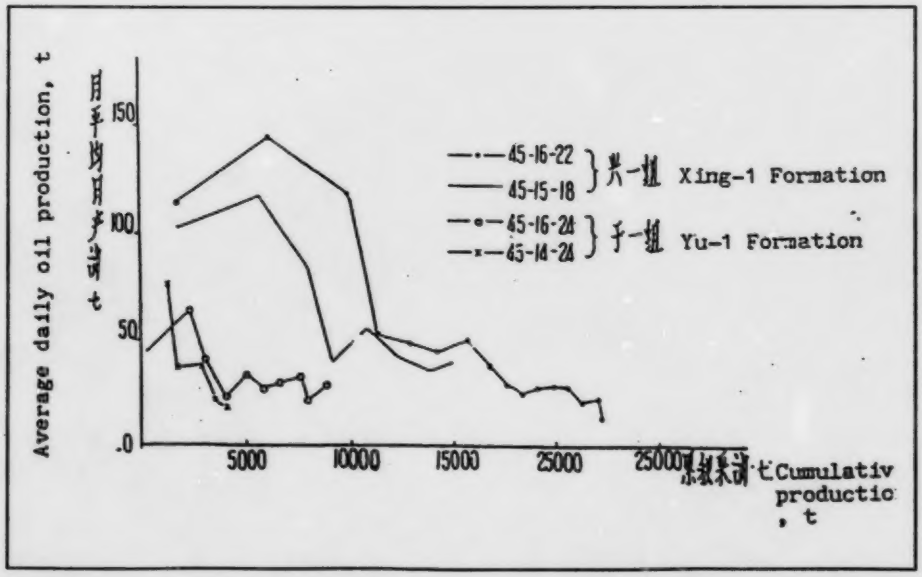


Figure 6. Relationship of daily oil production vs. cumulative production in Jin-45 block.

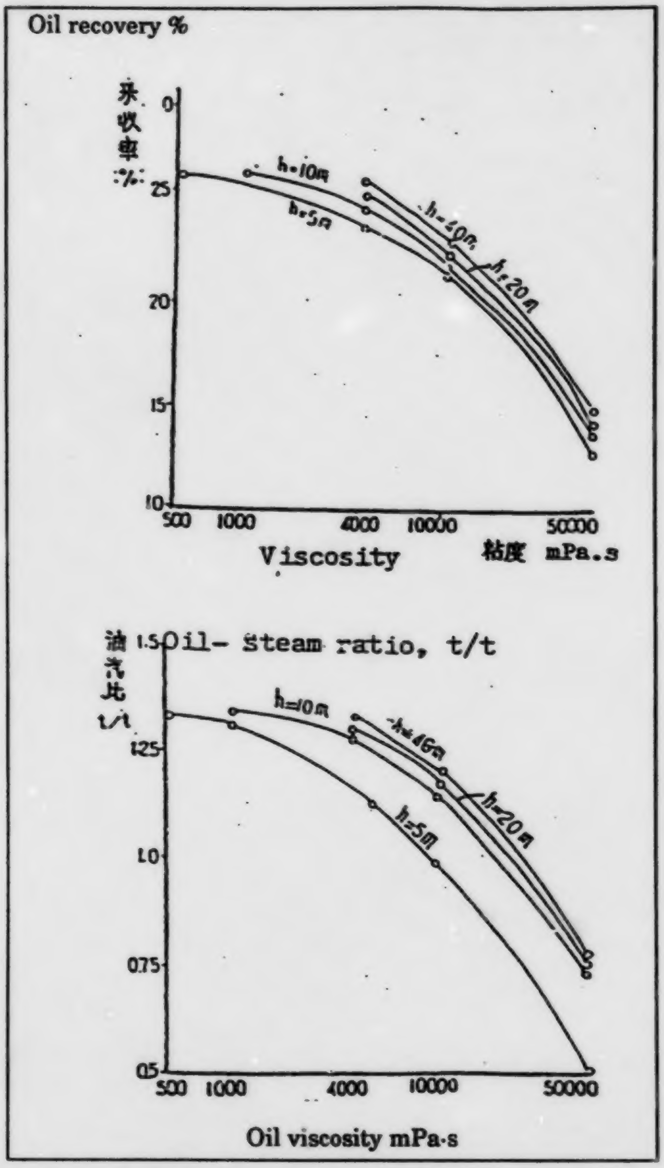


Figure 7. Effect of viscosity on results of steam stimulations.

2. **In a comparison of oil recovery in the said formations with similar kinds of oil, the best result, was achieved in the massive type oil pool, the medium-thick interbedded came next, and performance in the medium-thin interbedded reservoir was poor.**
3. **The parameters, which affected the steam stimulation performance in Liaohe oil field are oil viscosity, reservoir pressure, rock properties, and net/gross thickness ratio.**

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SESSION II
Well Completion

PRESTRESS WELL COMPLETION

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ABSTRACT

For preventing the early damage of casing due to thermal stress in steam injectors, a method of prestress well completion has been used for 300 wells in the Liaohe oil field since 1985. This technique has effectively prevented the problem of casing damage, prolonged the service life of wells, and established a solid foundation for steaming operations to recover heavy oil.

The process of prestressing casing with slip anchor in the bottomhole is performed once by means of conventional well cementing. The details are discussed in this paper. In a comparison with other techniques for prestress well completion, the process of this method was logically designed. It is simple to operate, reliable in performance, and provides a uniform distribution of the stress in the entire casing string. In addition, this technique is suitable for various zones and for different sizes of wells.

FORWARD

Since 1978, six heavy oil fields with 27 blocks such as Gao Sheng, Huan Xi Ling, Shuguang, etc., were developed in Liaohe oil field. Oil was produced from the initial primary production to the subsequent thermal recovery by using large-scale steam stimulation in 1986. There were more than 1000 steaming cycles carried out on wells at the end of 1989, and 4 million tonnes of steam had been injected.

During steam injection, casing is heated by hot steam, thus the steel expansion causes thermal stress. If this exceeds its yield strength, there would be plastic deformation in steel. Consequently, it will lead to casing failure, thread leaks or thread off. In order to prevent this problem, the casing should be prestressed in wells during completion. The prestressed casing would then counteract the thermal stress to a certain degree, that would be lower than the yield strength of casing. The chance of casing damage due to thermal stress in steam injection wells could be reduced.

Currently, there are three methods to prestress casing string in wells. The first one is the "two-step consolidation" method. The second is to prestress casing with cementing twice by using a short casing anchor at the bottom of casing string. The third is to prestress casing with a slip anchor cemented once in a conventional way. Liaohe oilfield invented the third method and extensively used it since 1985 in 300 wells, most of them are directionally drilled wells with maximum deviation of 27°, and the deepest well is 1700 meters. With respect to operation, the success ratio was 100%, also the largest pulling force at wellhead was 1100 kN, the maximum holding pressure was 20 MPa, and the cement slurry with 30% quartz sands returned to surface.

STRESS ANALYSIS OF PRESTRESSED CASING STRING IN STEAM INJECTORS

According to field operation condition, the following data are assumed:

l: the length of cement consolidated section, 1200 meters

ΔT_{max}: steam temperature, 400°C

C: coefficient of steel thermal linear expansion, $12.1 * 10^{-6}$ m/m°C

E: modulus of elasticity of casing N-80, $11.77 * 10^{-6}$ N/cm^2

σ_s: minimum yield strength of casing N-80, 551.13 kN/cm^2

A: coefficient of casing joint strength decreasing at the temperature of 400°C, 0.66

1. The maximum thermal stress in casing string due to high temperature is:

$$\sigma_{max} = E * C * \Delta T_{max} = 566.3 \text{ MPa}$$

2. Recommended prestress in casing string is:

$$\Delta\sigma = \sigma_{max} - A * \sigma_s = 202.6 \text{ MPa}$$

3. Recommended pulling force for casing string is:

$$P = \Delta\sigma * F = 869.0 \text{ kN}$$

where F is the cross section area of casing

4. The hoisting force to slip anchor is:

$$N = P - m - f - P_m = 525.8 \text{ kN}$$

where m: weight of equivalent casing string

f: equivalent friction between casing and borehole

P_m: axial force caused by drilling mud in the casing

From the above calculations, prestressed casing string with cementing is necessary for thermal well completions. The hoisting force for slip anchor in Liaohe field is $1.0 * 10^3$ kN with a safety factor of 1.90. This could meet the requirement for steaming operation at 400°C.

MECHANISMS OF LIAOHE SLIP ANCHOR

The casing string in steam injectors was prestressed with Liaohe slip anchor completed in one trip with conventional well cementing. In setting casing, the anchor as shown in Figure 1, was attached at the bottom of the casing string, that was run to the desired depth in the borehole. After conventional cementing, holding proper pressure in casing, rubber piston 5 pushed retaining pipe 9 forward by the action of mud pressure, and sheared off hanging pin 11. Then the pushing force, through eject stem 12, retaining piston 13 and leverage 15, thrusted slip 14 into bore well 16. Thereby casing string was steadily fixed in the wellbore and later pulled to the designed prestress condition by the hoisting system of rig. After that, the casing weight was put on the retaining bushing 2, and the production casing head was placed on the surface casing head. In order to control the height of casing head, short casings were used to adjust the height according to the demands. Also in the wells completed with directional drillings, the double-decker spacing centralizers were installed at the section with large curvature to prevent casing string leaning against the bore well and to improve cementing quality.

During cementing, cement slurry was replaced by mud. At this time, the casing string was periodically moved to prevent a sticking problem. This is helpful not only to upgrade cementing quality, also to refine the prestressing operation. The empirical value of anchor sliding displacement in field practice is about 10 to 30 centimeters.

SELECTION OF CASING

Figure 2 is a set of coordinate curves relating to temperature and modulus of elasticity of casing materials. From these curves, the modulus of elasticity of steel N-80 is different from those of J-55, P-105, and P-110. The N-80's modulus of elasticity decreases continuously with the increase of temperature from $19.2 * 10^6$ kN/cm^2 at ambient temperature to $10.8 * 10^6$ kN/cm^2 at 482.2°C. It drops significantly in the temperature intervals of 204.4°C ($16.6 * 10^6$ kN/cm^2) to 315°C ($12.1 * 10^6$ kN/cm^2). It should be mentioned that this temperature range is the normal steaming temperature in field practice.

Figure 3 presents a set of curves relating to temperature and yield strength of casing steel. It is observed that yield strength of steel N-80 is about constant from ambient temperature to 315°C, but the P-110's yield strength continuously decreases with the increase of temperature. Regarding other parameters, the coefficient of linear thermal expansion of various grade of steels changes insignificantly with the increase of temperature.

In a comparison of the results by using the mentioned parameters applied for the formula,

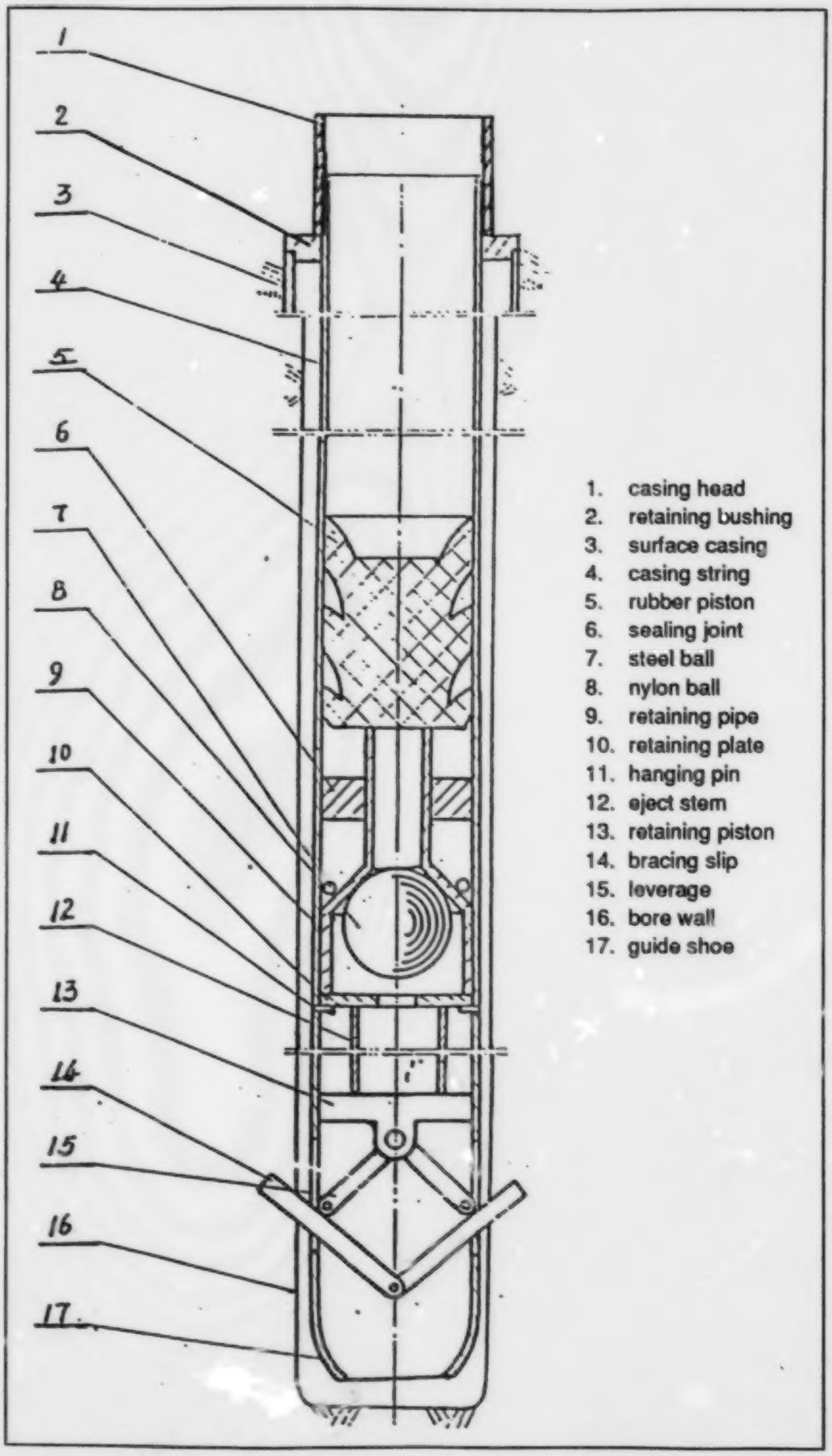

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
1. casing head
2. retaining bushing
3. surface casing
4. casing string
5. rubber piston
6. sealing joint
7. steel ball
8. nylon ball
9. retaining pipe
10. retaining plate
11. hanging pin
12. eject stem
13. retaining piston
14. bracing slip
15. leverage
16. bore wall
17. guide shoe

Figure 1. Pictorial view of Liaohe slip anchor model WA-1.

$$\Delta\sigma = E * C * \Delta T - A * \sigma_s$$

Obviously, the grade N-80 casing is a better candidate for steam injection wells.

FORCE ANALYSIS OF CASING IN PRESTRESSING OPERATION

After the bottom of casing string is steadily fixed by slip anchor, casing is lifted with hook in wellbore. At this time, there are six different forces as shown in Figure 4, acting on this string. Namely:

- upward pulling force: Q
- upward buoyancy from cement slurry: R
- tension from drilling mud inside: P
- pressure from cement slurry outside: p'
- downward pulling force from slip anchor: N
- fraction against bore well: f

The axial stress caused by action of the said forces is shown in Figure 5, from which, the stress originated by its own weight m and friction f would decrease with the increase of well depth h. On the contrary, the stress generated by the action of P and p' would increase with well depth. Superimposed these two, stress distribution in casing becomes relatively uniform.

With the increase of well depth, the radial tension P and pressure p' raise at the bottom of casing, similarly, the weight of

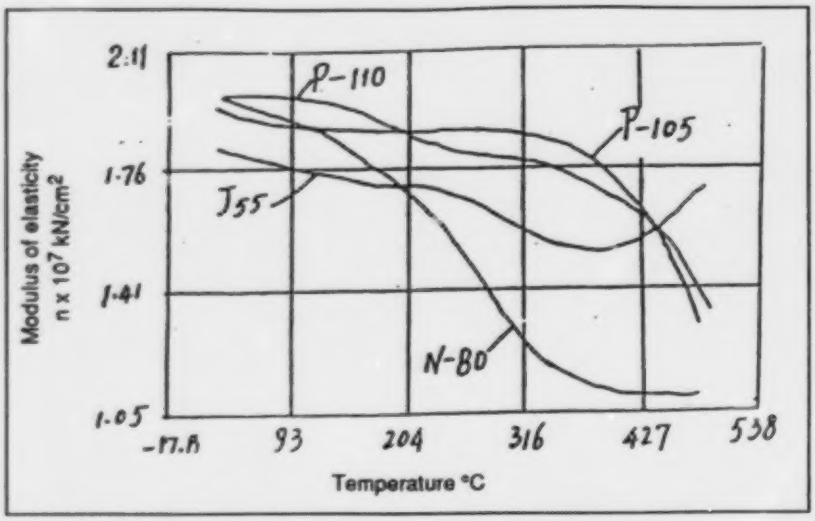


Figure 2. Curves of temperature-modulus of elasticity of casing.

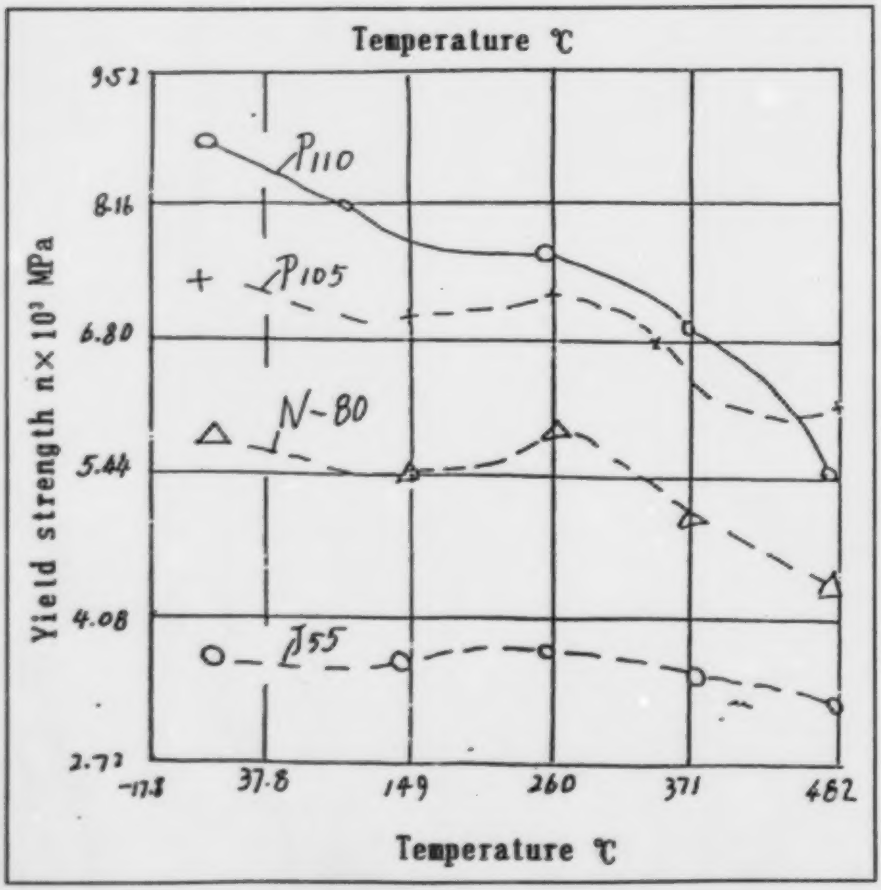


Figure 3. Curves of temperature-yield strength of casing.

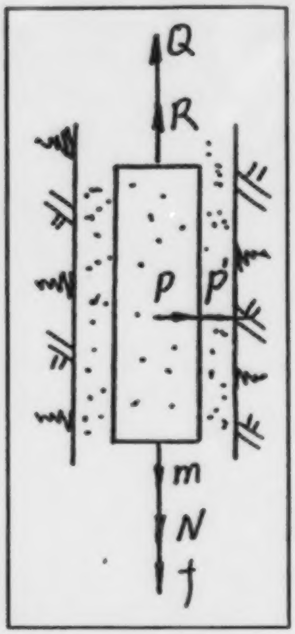


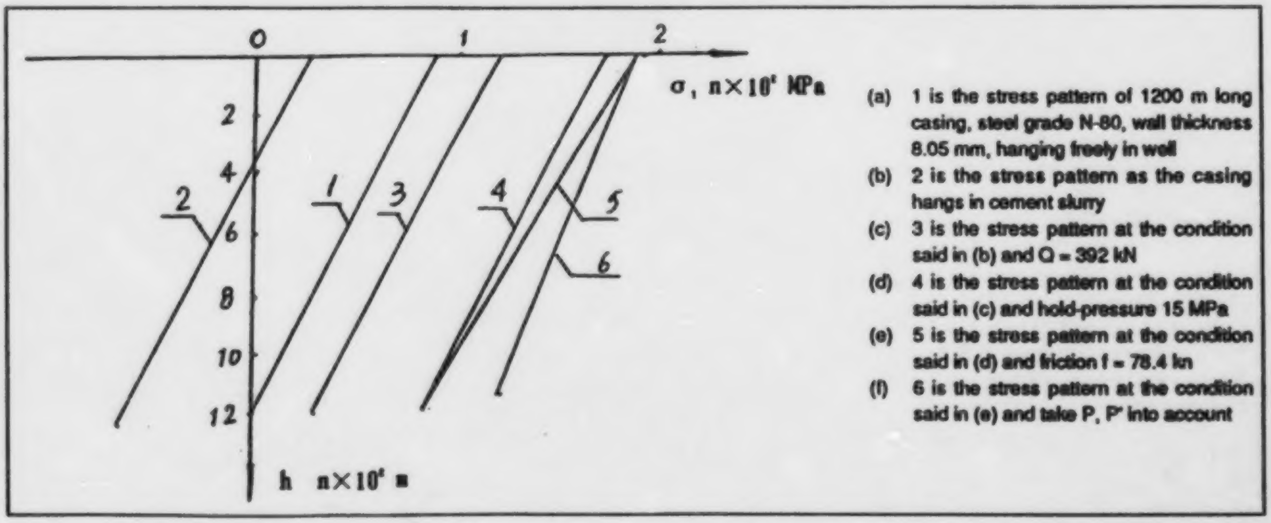
Figure 4.

casing m and fraction f acting on casing head also increase. However, the pulling force N working on the anchor would decrease under the condition of same prestress. Thus, the slip anchor is quite suitable for service in deep wells. During prestressing operation, the inside tension P and outside pressure p' of the casing with the aid of buoyancy force R will lighten the resultant load on wellhead.

FIELD PRACTICE

The following is a case in Liaohe field. The well was completed with prestressed casing string in September 1986 with the data as follows:

total depth	1090 m
casing depth	1083.69 m
anchor depth	1083 m
man-made well bottom depth	1071.69 m
mud density	1.10 g /cm^3
cement slurry density	1.89 g /cm^3
borehole diameter (anchor located)	275 mm
hold-pressure	15 MPa
hoisting force on hook	684.5 kN
hanging load of casing	107 kN
calculated force on anchor	500 kN
calculated casing head extension	89.7 cm
measured casing head extension	118.5 cm



(a) 1 is the stress pattern of 1200 m long casing, steel grade N-80, wall thickness 8.05 mm, hanging freely in well

(b) 2 is the stress pattern as the casing hangs in cement slurry

(c) 3 is the stress pattern at the condition said in (b) and Q = 392 kN

(d) 4 is the stress pattern at the condition said in (c) and hold-pressure 15 MPa

(e) 5 is the stress pattern at the condition said in (d) and friction f = 78.4 kn

(f) 6 is the stress pattern at the condition said in (e) and take P, P' into account

Figure 5. Well depth h-axial prestress of casing.

At the time of prestressing casing, casing string is in a complex condition with three dimensional stress. For further analysis, the principle of superposition and the generalized Hook's law are applied in order to simplify calculations.

$$\varepsilon_1 = \sigma_1/E - u\,(\sigma_2/E + \sigma_3/E)$$

hanging load of casing:

$$Q_s = W + W_m - R = 107.1\ \text{kN}$$
$$N = T - Q_s - f = 498.1\ \text{kN}$$

where W: gravity of casing string

W_m: gravity of mud inside casing string

R: buoyancy

Q_s: hanging load of casing after rubber piston collision

N: pulling force acting on anchor

T: hanging load on hook after casing string was prestressed

λ_1: extension caused by the pulling force N from anchor

$$\lambda_1 = (h * \Delta T)/(21 * A) = 61.3\ \text{cm}$$

λ_2: extension caused by the forces Q_s and f,

$$\lambda_2 = (h * \Delta T)/(42 * A) = 11.4\ \text{cm}$$

λ_3: extension caused by the forces P and P',

$$\lambda_3 = \varepsilon_1 * h\,[(\sigma_1/E) - u\,((\sigma_2 + \sigma_3)/E)] * h = 17.0\ \text{cm}$$

λ: total extension of prestressed casing string

$$\lambda = \lambda_1 + \lambda_2 + \lambda_3 = 89.7\ \text{cm}$$

λ_s: total extension of 1,200 m casing (N-80, well thickness 8.05 mm, O.D. 178 mm) at 340°C without prestressing,

$$\lambda_s = C * \Delta T * h = 61.6\ \text{cm}$$

η: additional extension rate (%),

$$\eta = (\lambda - \lambda_s)/\lambda_s = 45.6\%$$

The calculation results show that prestressed casing string in wells completed with the method stated above would not be damaged by thermal stress at the steaming temperature below 350°C.

CONCLUSION

The prestress well completion technique has been applied for 300 steam injection wells in Liaohe oil field since 1985. Up to date, there was no report regarding casing damage or abnormal operation on these wells, which have been putting in service for many years. The method of prestress cementing with slip anchor (model WA-1) has simplified the operating procedure, and the time spent for operation was almost the same as conventional well cementing. In addition, using this technique could shorten the well completion period at least by about two days than the mentioned second method, and save the drilling cost of about 8,204 Yuan (Renminbi) than the first method. The technique discussed in this paper not only met the geological requirement without deepening the well, but also effectively improved the cementing quality in steam injectors, and ultimately reduced the chance of well failures due to steam injection.

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DEVELOPMENT OF NOVEL SAND EXCLUSION STRATEGIES FOR VERTICAL AND HORIZONTAL WELLS USING FIELD AND LABORATORY RESEARCH

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ABSTRACT

A novel sand exclusion device developed by Canadian researchers and manufacturers uses a compressed metallic wool filter (Meshrite) to limit or exclude sand production associated with thermal heavy oil recovery from unconsolidated formations. The filter has been tested extensively in the laboratory and field with results from vertical and horizontal wells now being available. The paper describes a new laboratory and filter test apparatus which has been used for testing the Meshrite filter and other sand exclusion devices and discusses resent laboratory results from a new apparatus and previously used testing techniques. Field trials of the Meshrite filter and other sand control devices at AOSTRA's Underground Test Facility (coarse Athabasca sands) and Esso's Lone Rock pilot (fine Lloydminster sands) are discussed. Results indicate the Meshrite filter is prone to plugging in the Lloydminster sands in some applications but not the Athabasca sands. To reduce he risk of plugging, partial exclusion strategies are being developed.

INTRODUCTION

Considerable effort has been expended in an attempt to reduce the costs incurred as a result of sand problems in both thermal and non-thermal projects. Many sand control techniques have been developed including slotted liner, slurry or gravel pack, pre-pack, wire wrap screen and metallic steel wool filter (Meshrite filter) to limit the detrimental effects of sand entering the wellbore. Non-thermal heavy oil projects must produce some sand, at least early in the project, if they are to produce satisfactory volumes of oil. Producing this sand is possible since the high bitumen viscosity allows the bitumen to carry the sand. Thermal projects on the other hand don't necessarily need to produce sand to get satisfactory volumes of oil.

Even with extensive laboratory and field testing, the standard sand control techniques have often met with limited success in the unconsolidated oil sands of Alberta, Canada, particularly with thermal projects. Thermal operations have been utilizing the same sand control techniques as used for conventional recovery. The increased problems associated with thermal projects has lead to the development of the Meshrite steel wool filter. Texaco Canada Resources (now known as ESSO Resources Canada) and the Alberta Research Council initiated a sand control project in 1981 (Toma et al.)[1] studying sand control methods suitable for the severe in situ conditions associated with thermal projects.

A Hassler-type high pressure cell (ARCONSOL) was designed to test and compare a number of sand control devices, and develop in the laboratory, new field strategies such as the novel Meshrite filter. The test reproduces satisfactorily, the sand migration in the near wellbore and the retention mechanism for a typical set through completion (perforated cased hole with internal sand control liner). A new pre-packed filter with stainless steel wool sandwiched between coarse steel cloth was designed and successfully tested in both the laboratory and the field.

For studying plugging situations and developing novel sand control in open hole completion (sand control liner run into open hole) environments, a new sand control test apparatus has been designed and tested. Preliminary tests with the new apparatus have indicated that the apparatus does provide repeatable results.

Field results from two projects are discussed which support the laboratory program results: AOSTRA's Underground Test Facility, in the Athabasca oil sands, and Esso's Lone Rock pilot in the Lloydminster heavy oil deposit.

LABORATORY PROCEDURES

Mobilization and Transport of Fines

Observations made during field and laboratory investigations on sand control, suggested a difference between the mechanism of solids transport and retention for set through completions where a good contact between the filter media and formation is achieved, and an open hole completion.

In order to understand the capture mechanisms and to suggest the best design and operation criteria, it was decided to develop two distinct laboratory tests for simulating set through and open hole conditions. Figure 1 illustrates a three-zone filtration model, used to explain laboratory and field observations. Zone 1, the "far-away," contributes to the production of fines which are mobilized during the recovery process. Fluid rates, as well as interfacial sand-fluid properties, are essential to the fines mobilization process. Distribution of sand grains in the fines producing zone, sometimes illustrated by a specific percentile point such as D10 and D50, as well as through the ratio C = D40/D90 ("uniformity coefficient"), is of extreme importance for assessing a certain sand control strategy in the laboratory. Retention and transport of fines through zone 2 or the near-wellbore zone, is controlled by the sand control device as well as by the size of sand initially present. ravel packs used in some completions usually fills this zone. For thermal processes where high temperature-high pH conditions would dissolve silica used in the standard gravel pack or for horizontal wells, where a good placement of the gravel can be a difficult technical problem, gravel packing is usually avoided. In open hole completions zone 2 is represented by produced fluids carrying fines. The interface of the sand control device and zone 2 is a relatively thin layer where, depending on size and shape of the sand control perforations and sand grains as well as on stress regime and flow rate, a stable sand arch structure (Cleary et al.)[2] can be achieved or destroyed with important implications on the sand control process. Also, depending on the structure of the filter media and openings, a filter cake formed at the filter interface can significantly increase the pressure drop and reduce the production of fluids.

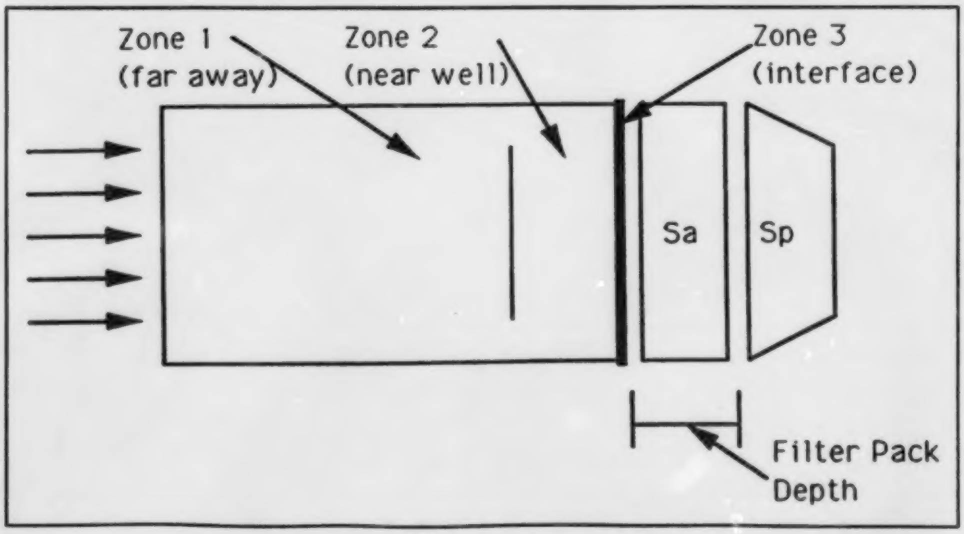


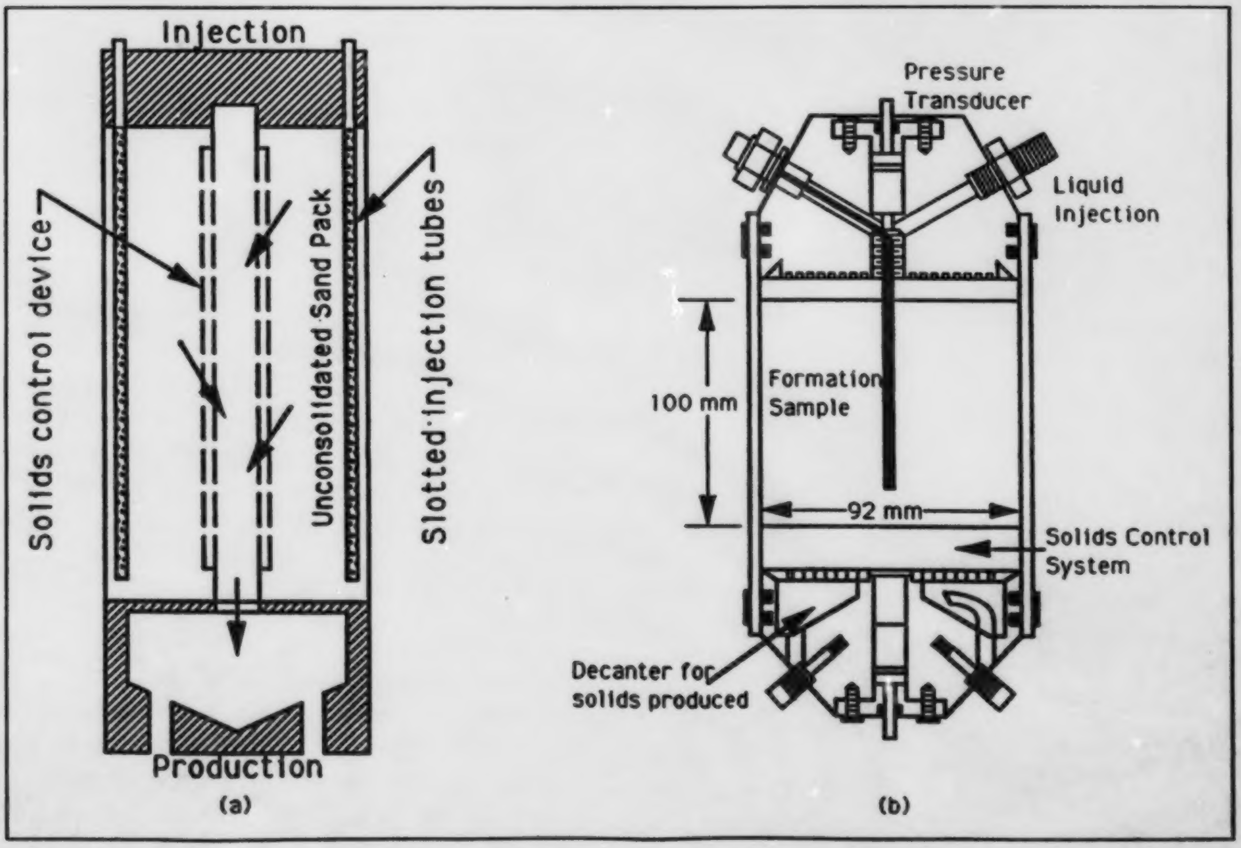
Figure 1. Schematic of the process of solids transport and retention.

A zone of accumulated sand (Sa) is characteristic of filter media using packed materials such as the Meshrite filter, geotextile wool or dual screen prepacks (Baker Sand Packs). Progressive plugging of the pore structure takes place and the design of such filters should aim to reduce the rate of the pore plugging process. Producing some of the fine sand can be beneficial to maintaining stable arch structures and reducing the risk of plugging (Coberly)[3] and one of the important objectives of recent laboratory investigations was to develop strategies for achieving this partial retention.

Set Through Completions

A laboratory solids control test apparatus (ARCONSOL) developed to assess the overall performance of different sand control strategies has been used at the Alberta Research Council since 1982. The test uses an unconsolidated core which has been properly extracted and preserved, or a laboratory simulated sand blend which closely reproduces the sand grain distribution of an actual core (Figure 2). To reproduce the downhole sand stress condition, a lead sleeved core, which is in perfect contact with the sand control device (set through completion test), is introduced into a high pressure vessel. A constant temperature-constant flow rate fluid is piped to the pack; a back pressure control and sampling device situated outside the pressure vessel, completes the apparatus.

Figure 2 (a, b), shows schematics of the test rigs used for assessing flat or cylindrical shapes of various filter media exposed to a radial (a) or frontal (b) flow situations. Table 1 illustrates the standard test


Injection
Solids control device
Unconsolidated Sand Pack
Slotted injection tubes
Production
Pressure Transducer
Liquid Injection
100 mm
Formation Sample
92 mm
Solids Control System
Decanter for solids produced

(a) (b)

Figure 2. Schematic of the radial and frontal ARCONSOL test rigs.

Table 1. Standard sand control test conditions for set through ARCONSOL tests

Injection	water (T = 22°C)
Flow rate	10 kg/hr (0.8 m^3/day per meter of well)
Backpressure	100 psig (0.69 MPa)
Overburden pressure	500 psig (3.45 MPa)
Test duration	420 minutes

conditions for the linear and radial displacement ARCONSOL test rigs. A constant flow rate injection control was used during the tests.

Continuous measurements of pressure drop across the filter and the balance of produced fines were used to quantify different filter media. The best sand control devices were those indicating the minimum amount of sand produced, the smallest increase in pressure drop during the test as well as the lowest initial pressure drop.

Open Hole Completions

To investigate the plugging process of a filter media and develop design and production strategies for reducing the risk of plugging, an experimental rig for simulating severe sand conditions encountered in an open hole, was designed and tested at the ARC in 1989.

Figure 3 illustrates the new experimental test apparatus, for simulating severe sand conditions, that was designed and constructed by the ARC to simulate open hole completions. It consists of a 15 litre, heated and insulated pressure vessel equipped with a magnetically coupled stirrer. The stirrer is speed controlled and the vessel has both pressure and temperature control capabilities. The test piece is held in a horizontal position at a controlled constant temperature in a sample holder. An electronic balance, connected to a process control computer, is situated downstream from the sand control device. Also monitored and recorded, are the pressure drop readings across the test piece as well as those across the piping system associated with the test piece and the holder. The on-off valve located between the two vessels is opened at the beginning of the experiment by a signal generated by the computer and is closed automatically when a pre-determined amount of fluid has collected in the container situated on the electronic balance.

A standard experimental procedure was used throughout. The filter was mounted in the holder while the test fluid was loaded into the stirred pressure vessel which was at a temperature of 40°C for all experiments in this series. Sand (0.1 or 0.2 wt%) was added to the vessel and then stirred for 45 minutes prior to the test, to achieve some level of homogeneity. The valve located between the stirred vessel and the vessel containing the test piece was then opened and the fluid was allowed to flow through the filter under an applied head pressure of 138 kPa (20 psi). Each experiment tended to last from 100 to 1000 seconds depending on the interaction of the fluid and the filtration device. Data was assembled and compared on the basis of formation sand (Athabasca or Lloydminster), and type of filtration device employed.

EXPERIMENTAL RESULTS

Key Filter Parameters

The experimental results presented were selected from a large number of data and projects in order to substantiate the influence of completion type (open hole versus set through), formation grain size, and type of solids control device to be used, as guidelines for future investigations. Selecting the optimal well completion for a specific formation and production strategy, should always be investigated using a particular set of conditions.

A Meshrite filter device is used as a standard filtration system. By changing the compression applied to the metallic wool, density and porosity can be easily modified. A conventional compression factor (CF) is used in laboratory experiments. For a medium fiber grade equations 1 and 2 are used to determine overall density (ρ) or porosity (ϕ):

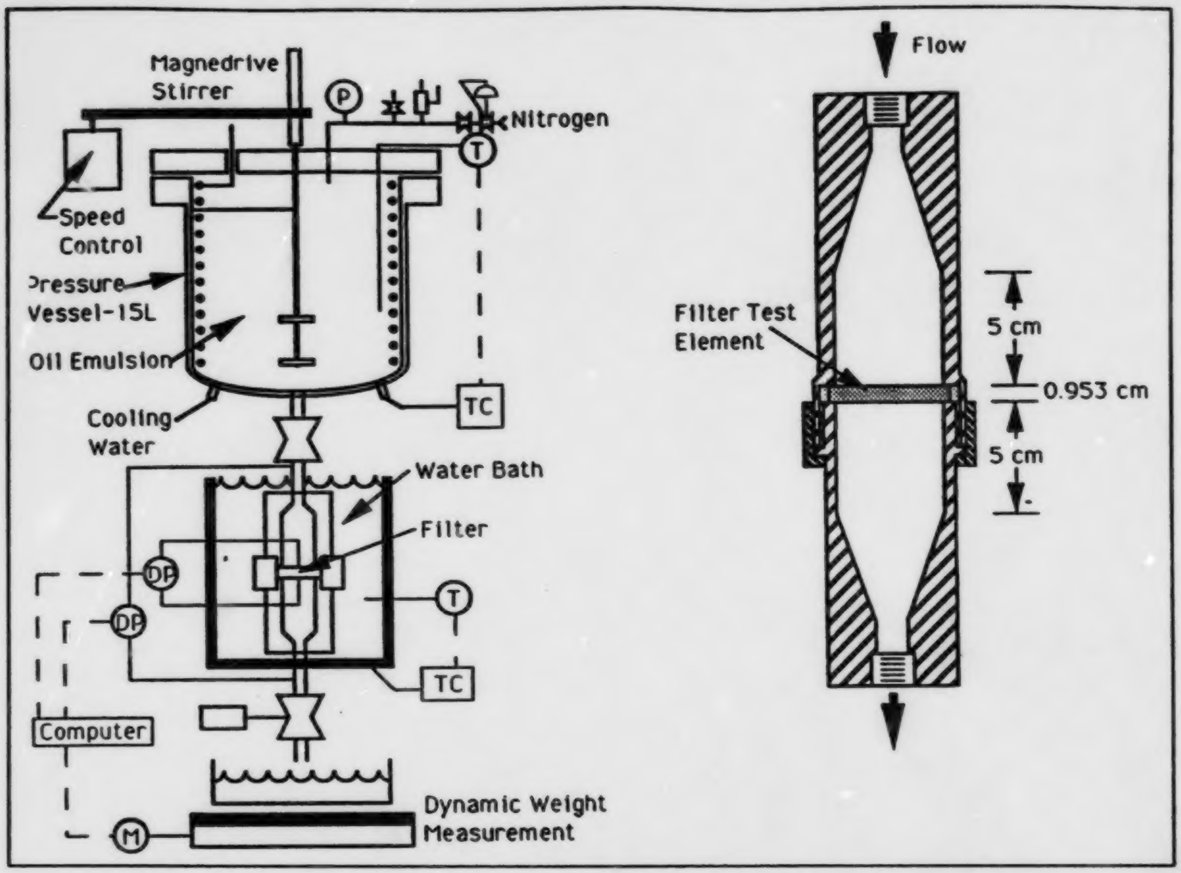

Magnedrive Stirrer
P
Nitrogen
T
Speed Control
Pressure Vessel-15L
Oil Emulsion
Cooling Water
TC
Water Bath
Filter
DP
DP
T
TC
Computer
M
Dynamic Weight Measurement
Flow
Filter Test Element
5 cm
0.953 cm
5 cm

Figure 3. Laboratory cell for simulating open hole flow.

(1) $\rho = 1 - CF\,(1 - Eo)$

where Eo = 0.995 is the porosity of the non compressed wool (medium grade).

(2) $\phi = 1 - \rho/7.5$

Filter Efficiency

The filter efficiency, E (equation 3), can be obtained from experimental data by measuring the amount of solids produced (Sp) and solids accumulated (Sa) in the body of a porous filter at the end of a standard test (see 1):

(3) $E = 1 - Sp/(Sp + Sa)$

Figure 4 illustrates the influence of compression factor and formation grain size on the efficiency of a Meshrite filter used in a set through completion. To achieve a total exclusion strategy, the metallic wool should be compressed to a value above a critical compression which is approximately 15 for a sand having D50 = 152 µm and only 9 for D50 = 180 µm. The sand used for the tests is illustrated in Figure 5. A relatively small reduction of sand grain size (D50 reduced from 180 to 152 µm) has therefore a detrimental effect on maximum achievable efficiency which is reduced from approximately 90 to 85%, as shown in Figure 4.

Fines Accumulated

A significant reduction of filter permeability with

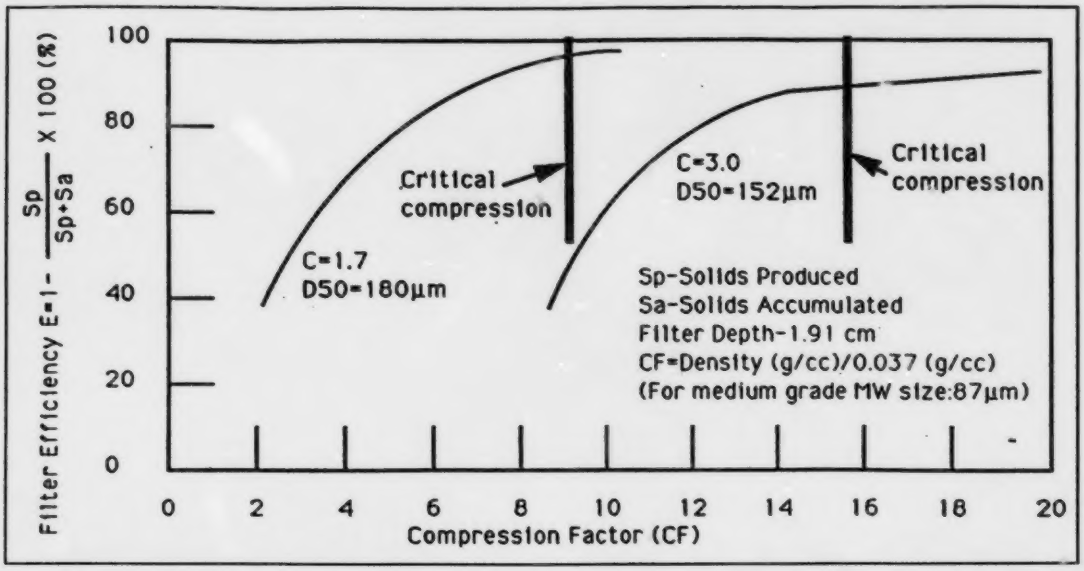


Figure 4. Influence of compression factor and formation on filter efficiency for set through completion.

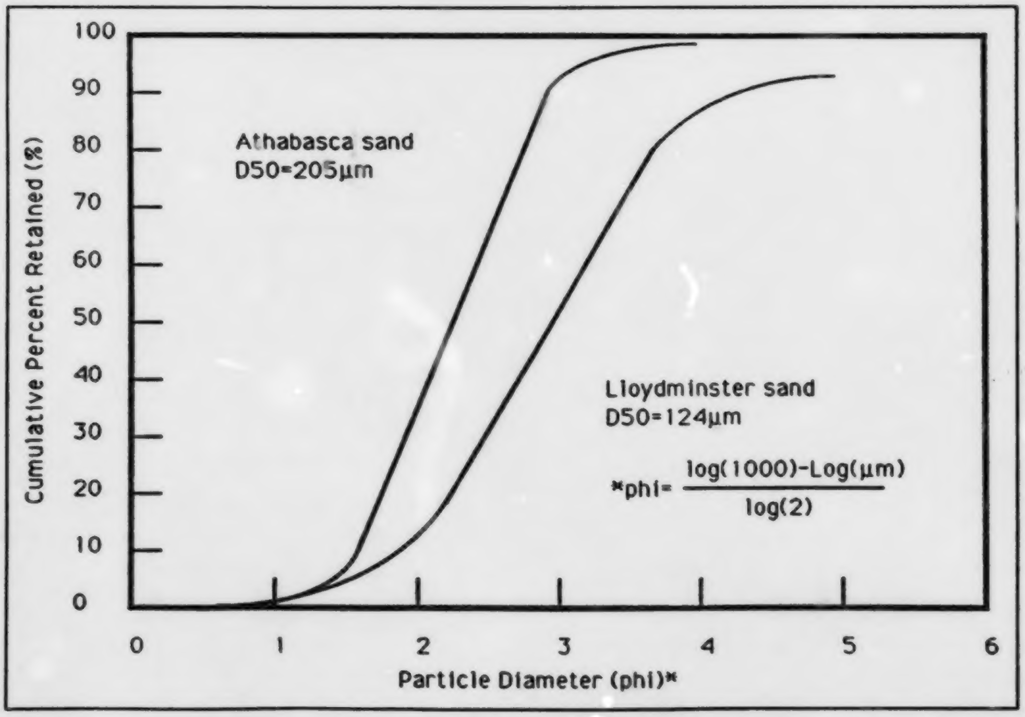


Figure 5. Sand grain distribution for typical Alberta oil sands.

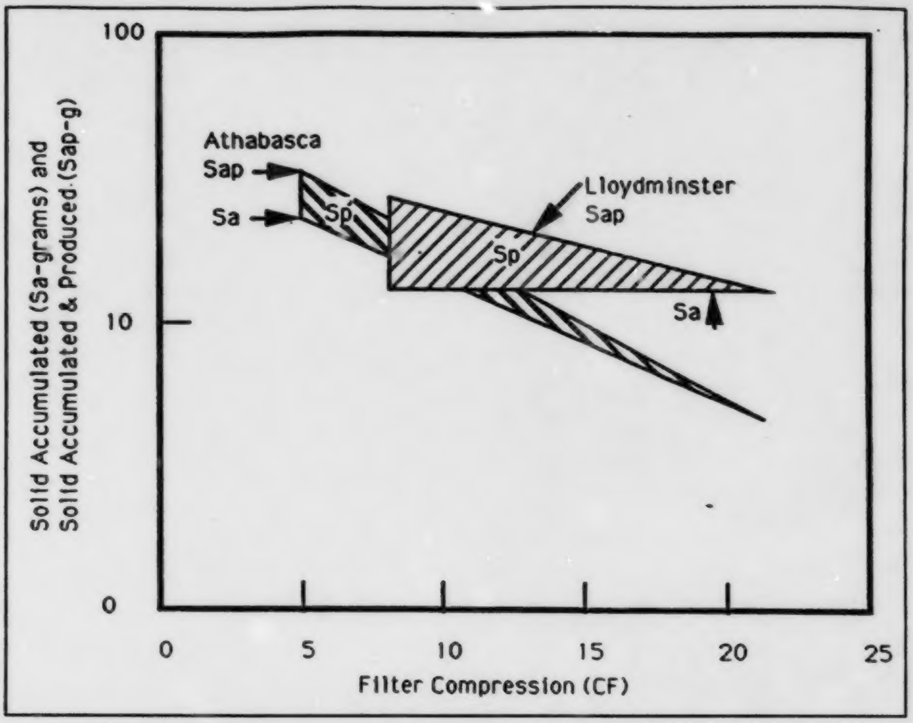


Figure 6. Effect of filter compression versus solids produced and accumulated.

the amount of fines accumulated was observed in the field for fine grained formations such as in Lloydminster, Alberta. A laboratory program was extended to observe and develop novel strategies to reduce the plugging risk. The set through ARCONSOL test rig was used to separate the effect of filter compression on the amount of fines accumulated and produced. Both Athabasca and Lloydminster sand samples were used. Figure 6 illustrates the effect of filter compression (CF) on the balance of solids produced and accumulated for a large number of laboratory tests using Athabasca and Lloydminster sand grain distribution presented in Figure 5.

For coarse grained formations such as Athabasca, increasing the filter compression has a significant effect on the reduction of the total amount of fines produced and accumulated. For finer formations such as Lloydminster, increasing the filter compression will have only a limited effect on the relative reduction of solids transported through the filter (Sap = Sa + Sp), whereas the amount of solids accumulated will be almost unchanged. Therefore, the Meshrite filter acting as a total exclusion device, is retaining most of the solids and will progressively plug. This laboratory observation was consistent with field tests of the Meshrite filler performed in Athabasca and Lloydminster unconsolidated oil sands formations and was the starting point for further investigations into reducing the plugging risk observed for fine grained formations through partial exclusion strategies.

Plugging Behavior in Open Hole and Set Through Completions

Plugging the Meshrite filter is indicated in Figure 6 using the balance of sand accumulated at the end of a standard ARCONSOL test simulating a set through completion. Figure 7 compares the variation of initial to final filter permeability with compression factor for laboratory simulated set through and open hole completions for Athabasca sand. As observed from Figure 6, increasing the compression factor has a positive effect on reducing the accumulation of solids and increasing the permeability ratio when a sa through completion is used in Athabasca Figure 7, comparing the filter permeability reduction with compression factor for set through and open hole completions, indicates an opposite effect for the two completion. This suggests a different plugging mechanism occurring for open hole and set through completions. While for a perfect set through

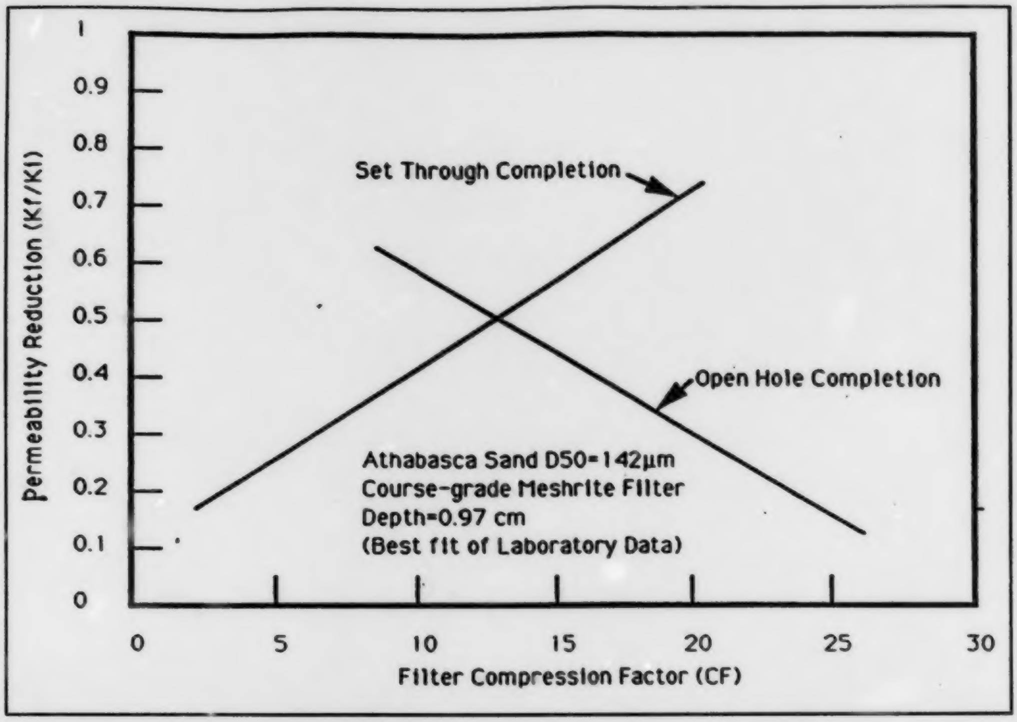


***Figure 7.** Influence of compression factor to permeability reduction for laboratory simulation.*

completion, increasing the compression will result in less solids entrained in the filter and less solids accumulated, for open hole situations exposed to a constant sand slurry influx, the capture and retention increases with compression. Furthermore, it was observed that in an open hole situation, fines are retained in a thin cake layer situated at the filter-fluid interface as well as in the bulk of the filter. Table 2 summarizes the effect of the cake layer and bulk accumulation of fines on pressure drop increase for standard laboratory tests using aqueous and oil emulsion slurry now. It indicates that the overall increase in pressure drop (for the same flow rate) averaged 52% of the initial value for coarse filters exposed to an aqueous slurry and 80% of the initial value for medium-grade wool filters. The pressure drop increase reached 71% and 96% of initial pressure drop when coarse and medium-grade filters were exposed to an oil emulsion slurry flow. The contribution to pressure drop of the thin layer of cake was in a range of 35 to 55% for all groups. It should be noted that pressure drop due to formation of a cake layer was higher in an aqueous slurry than in an oil slurry. The overall increase in pressure drop was in

***Table 2.** Contributions of sand accumulated in the body of the Meshrite filter and of cake formation to pressure drop increase*

Filter wool grade	Aqueous slurry coarse	Medium	Oil emulsion slurry coarse	Medium
1. Overall (%)	69	75	91	70
2. Participation of cake (%)	45	51	41	35

the range of 80 to 100% for medium-grade wool and 50 to 70% for coarse-grade wool.

Filter Comparison and Rating Criteria

Comparison of different sand control devices should take into account the specific conditions of the formation, the process and the completion. Laboratory tests should investigate a range of values for each key variable as sometimes instability phenomena controlling arching and capturing will take place within a small variation of a variable. An overall appreciation of a certain device, which includes sand production and pressure drop modification data, is considered a first step in such investigations.

Table 3 presents preliminary results of a comparative study between a Meshrite (medium grade, compression 20) and a standard wedgewire device (0.010" for Lloydminster sand and 0.015" opening for Athabasca sand).

The following relative parameters are indicated

(a) the ratio between produced sand balance of wedgewire (ww) and Meshrite (m),

(b) the ratio between initial and final pressure drop for the two filters

[(Dp) i/(Dp) f]m/[Dp) i/(Dp f] ww, and

(c) the ratio of initial (clean) pressure drop of the two filters (Dpi) m/(Dpi) ww.

According to this preliminary laboratory evaluation, the Meshrite filter can retain 50-70 times more solids than a standard wedgewire filter in a set through completion and approximately 4 times more in an open hole coarse, sand situation. The increase of pressure drop in the Filtration device is approximately 50% higher for the Meshrite than for the wedgewire filter in a sa through mode and approximately 600% higher for an open hole exposed to coarse Athabasca sand. In absolute terms, however, permeabilities for the Meshrite filter were still several darcies at the end of the tests.

New laboratory and field investigations aimed at reducing the risk of plugging in the Meshrite filter through a novel design to achieve partial exclusion are being conducted. Also, new improved designs of the wirewound filter aiming to enhance the bridging mechanism for both open hole and set through completions are undergoing continuing laboratory investigations.

FIELD TESTS

UTF Field Trial

AOSTRA has been conducting thermal in situ bitumen recovery tests at the Underground Test Facility (UTF), northwest of Fort McMurray, Alberta, Canada (Figure 8). One of the processes being studied at the UTF is the Steam Assisted Gravity Drainage (SAGD) process. Phase A tests of the SAGD process began in December, 1987. The SAGD process uses horizontal wells drilled in pairs from an underground mine. A schematic of the SAGD wells is shown in Figure 9. The Phase A wells are approximately 150 m long with 52 m completion intervals. Liner diameters are 140 mm and 178 mm. The horizontal wells are drilled from the mine

Table 3. Relative performance Meshrite over standard wire wedge

		Sand produced $\frac{(SP)\ ww}{(SP)\ m}$	Press. drop Inc. $\frac{(Dpf/Dpi)\ ww}{(Dpf/Dpi)\ m}$	Pressure drop Init. $\frac{(Dpi)\ ww}{(Dpi)\ m}$
Open hole	Athabasca	n/a	6.2	0.2
Set through	Athabasca	100	2.1	0.1
Open hole	Lloydminster	n/a	2.8	0.4
Set through	Lloydminstger	500	0.9	0.2

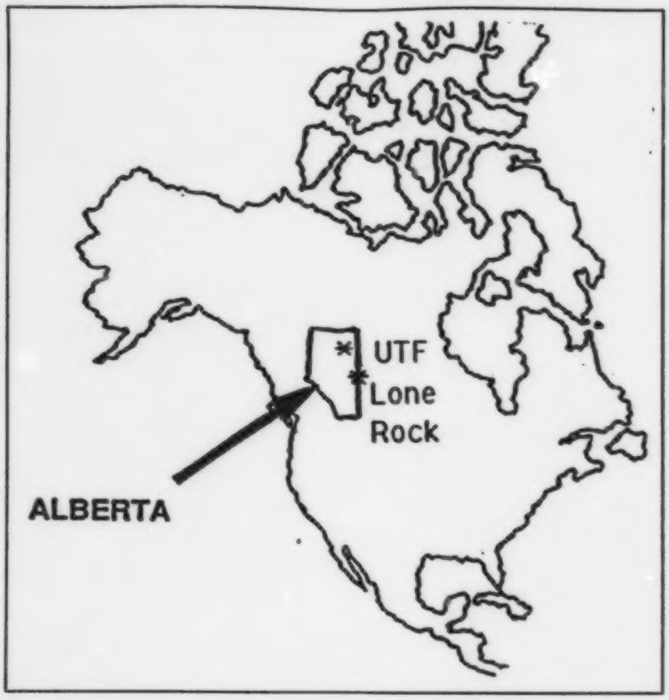


Figure 8. Location of the Underground Test Facility.

tunnels, upwards and along the base of the oil sands. The production wells were drilled low in the reservoir with the injection wells 3 m to 5 m above. Injection pressures are maintained below fracture pressure and production is controlled with a steam trap control, producing steam condensate at conditions slightly cooler than saturation. The result is very efficient use of steam while withdrawing the maximum amount of liquid fluids (Edmunds et al.).[4] Phase A geology, as shown in Figure 10, consists of approximately 20 m of exploitable oil sands. Generally, the reservoir is rich and clean in the bottom half and more shaley and interbedded in the upper half. The shale break (Unit F) shown in Figure 10 is not consistent with the Phase B test arc and most of the commercially identified UTF lease. The McMurray sand at the UTF site is a fine, moderately well sorted, unconsolidated sand, as shown in Figure 11. The median grain size is about 175 mm (0.0069 inches or 80 mesh). The mineralogical composition of a typical McMurray sand is 91–97% quartz, with small amounts of chlorites and illite clays.

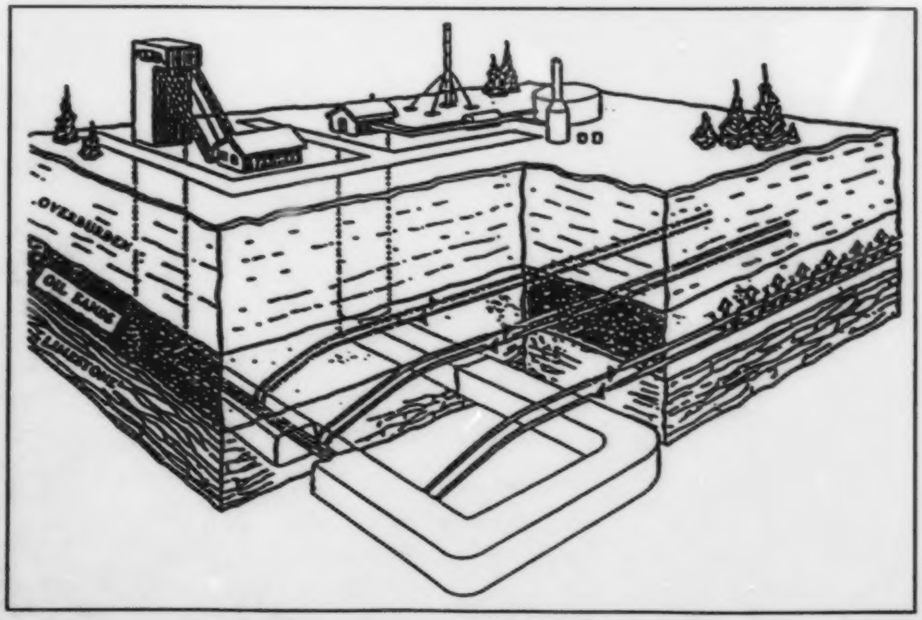


Figure 9. Schematic of the Underground Test Facility.

Sand control has traditionally been a significant problem in the Athabasca oil sands with projects experiencing sand production problems and/or productivity impairment due to sand exclusion techniques (Redford).[5] Horizontal well processes have the advantage a greatly increased hole length in the reservoir is possible, meaning that lower (than vertical wells) inflow rates per unit length may be adequate. This reduced inflow per

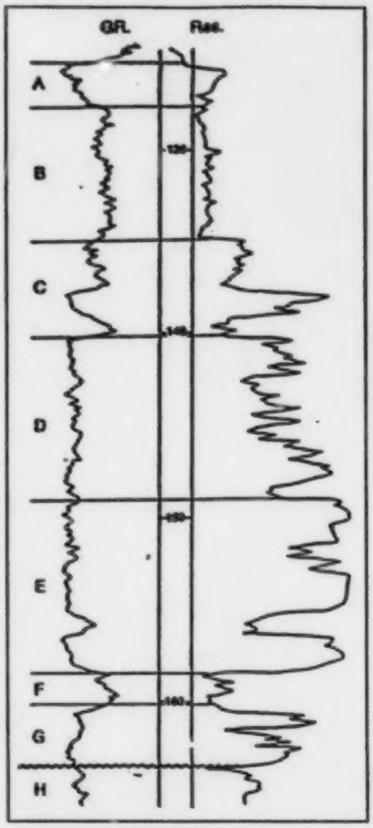


Figure 10. UTF Phase A geology.

unit length means that sand is less likely be drawn through the sand control device. The disadvantage, however, is sand which does pass through may settle in the well because of low liquid velocities and horizontal fluid flow. To maximize The opportunity for successful implementation of the SAGD process it was decided to evaluate both the conventional wire wrap screen and the patented Meshrite stainless steel wool filter (Toma et al.).[1] Other techniques were reviewed but rejected for the following reasons: gravel packing: underreaming required, packing of long intervals was not proven, and the high cost; slotted liners: small, precise slots are not available; perforated completions: unconsolidated reservoir, excessive sand production; prepack screens: variable experiences. A number of methods for sizing the wire wrap screens is reported in the literature[6,7,8] which results in a range of recommended gap widths, for the UTF, from 365 mm (0.009") to 480 mm (0.012").

In 1986 a laboratory program was conducted at the ARC (Edmunds)[4] to evaluate a number of sand control elements for the UTF. Elements tested, at ambient conditions, included the Meshrite filter, 0.005", 0.010", 0.014", and 0.018" wire wrap screens. The experimental apparatus (ARCONSOL) is shown schematically in Figure 2(b). All the tests produced very little sand (less than 4 gm per test), with the exception of The 0.018" screen which produced 70.5 gm of solids. Following the non-thermal tests, thermal testing of the Meshrite filter and the 0.005" and 0.010" wire wrap screens was carried out. The results from the thermal runs are summarized in Table 4. The Meshrite filter showed a significant reduction in permeability by the end of the 60 hour test, however the filter permeability remained high at 500 darcies. The 0.010" wire wrap screen produced about 10 times the volume of solids produced by the Meshrite filter.

Following The laboratory tests it was decided to complete one well pair with 0.005" wire wrap, another with 0.010" wire wrap, and the other with the Meshrite filter. To reduce costs, completion screens were alternated with blank screens, resulting in 2 m of screen for every 6 m of completion (liner sections are limited to 3 m because of underground drill rig size restrictions). Results to-date have been encouraging. Only infrequent traces of sand have been reported and there appears to be no build up of sand in the horizontal sections of the wells, although this can not be confirmed since none of the wells have required a workover. The good performance of the sand control is attributed to the low inflow rates per unit length and the production well controller which does not allow steam to be produced (although steam may exist in the production well.

With the success of the Phase A tests, Phase B drilling began in August, 1990. The Phase B wells will be completed over a 500 m interval, greatly increasing contact with the reservoir. Both wire wrap screen gap sizes and the Meshrite filter have performed well during the Phase A tests and both methods of sand control are being installed in the Phase B wells.

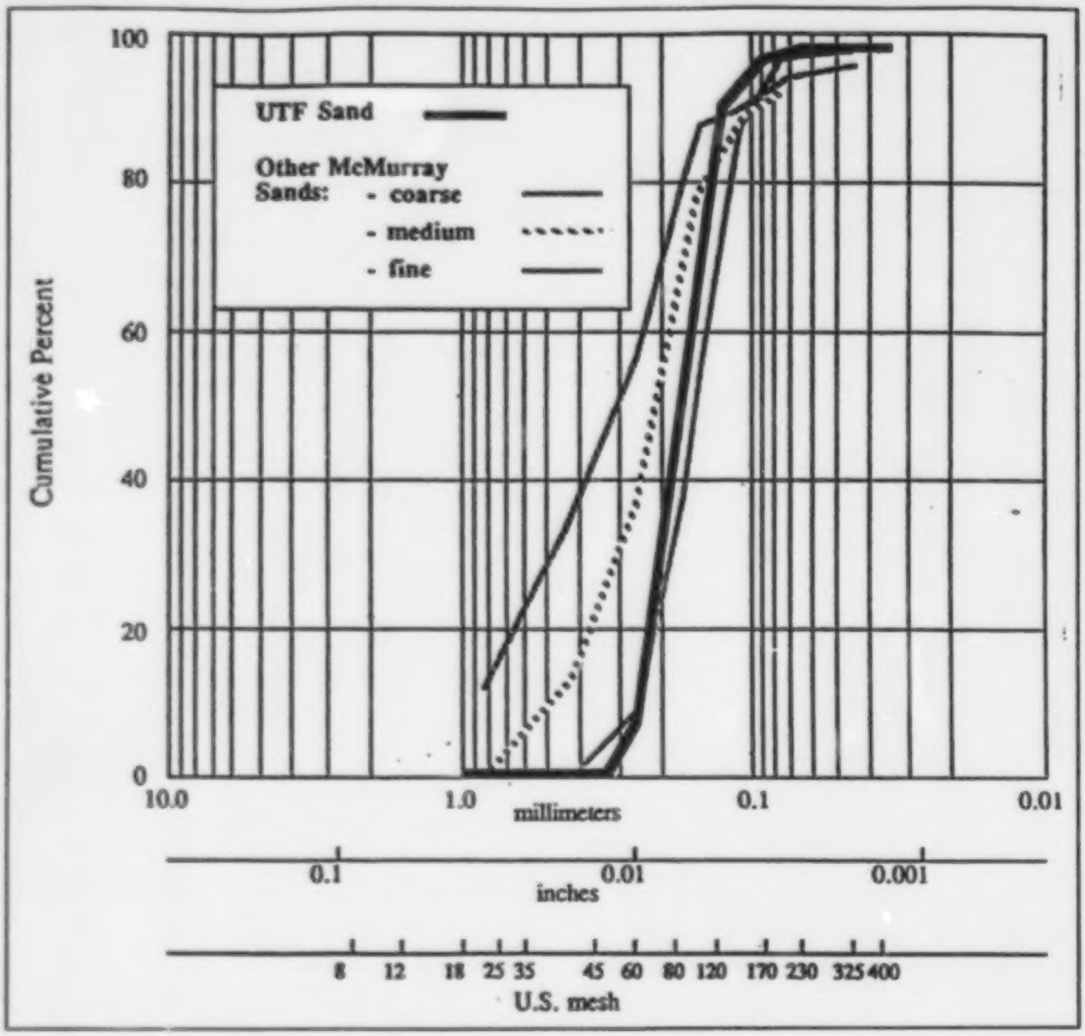


Figure 11. UTF sand particle size distribution.

Lone Rock Steam Flood Pilot

The Lone Rock steam flood pilot is located near the border of the provinces of Alberta and Saskatchewan, 29 km southeast of Lloydminster. The project is comprised of three adjoining inverted seven spot patterns. The pilot produces from the Sparky formation. This formation has very fine sand with a D50 of 100 mm and the oil has a viscosity of 650 cp at the original reservoir temperature of 20°C.

Located adjacent to the steam flood pattern is a primary production well. This well was cased through the Sparky reservoir and perforated. No sand control was used during primary production and the well was producing an average of 12 m^3/day total fluid. During operation of the steam pilot, a response to the steamflood was noticed at this well. Although total fluid production did not increase as a result of communication with the main steam pattern, the primary well did begin to produce prohibitive quantities of sand. To control the sand, the newly (1986) developed Meshrite filter was installed. The first filter was installed in June, 1986, but due to poor filter media quality, it did not control sand inflow. The first filter was removed and a second filter, with

Table 4. UTF laboratory thermal sand control results

Sand control element	Water flow range (cc/hr)	Maximum pressure drop (kPa)	Reduction in filter permeability	Solids production (g)	Comments
Meshrite Filter (commissioning)	30–760	25 at 760 cc/hr (636 D remaining)	56%	5.45	Sand penetrated only two of 24 wool layers.
Meshrite Filter (operational limits)	30–7000	exceeded 500 at 7000 cc/hr	69% (575 D remaining)	8.88	Pressure drop exceeded 300 KPa in high flow tests. Silica deposits and corrosion of stainless steel detected.
0.010" screen	30–200	70 at approx. 60 cc/hr	Not applicable	41.30	Core sleeve collapsed three hours into the test.
0.010" screen	30–760	<30 Kpa over entire flow range	Not applicable	86.0	Sleeve collapsed during first flashing test, 37 hours into run.
0.005"	30–1500	500 kPa @ 1500 cc/hr	Not applicable	7.10	Pressure drop exceeded 300 kPa at 1500 cc/hr subsequent to the flashing tests.

improved quality 4. control, was installed in August, 1987. The well was again put on production, however, total fluid rates dropped to less than 1 m^3/day. This plugging response of the Meshrite filter in the Lloydminster sands appears to occur because fine sands combined with viscous fluids cannot efficiently flow through the filter.

SUMMARY

There is a marked difference in laboratory and field results with the Meshrite filter between clean, coarse Athabasca sands and finer Lloydminster sands. In both applications the filter very effectively stops sand production. Athabasca sands tend not to plug the filter or detrimentally reduce filter permeability. Lloydminster sands on the other hand tend to plug with sand and fines,.significantly reducing filter permeability, solving The sand problem but making the well uneconomic. Esso has undertaken to modify the present Meshrite filter design; the new design should allow the passage of some fines with the produced fluids.

Both the Meshrite filter and 0.005" and 0.010" wedgewire screens have been very effective at stowing all sand production at the Underground Test Facility in the Athabasca oil sands deposit.

The Meshrite filter, in its original design significantly reduced fluid production at a well near the Lone Rock pilot. This plugging is not well understood but appears to be a result of the combined effect of fines accumulation in or on the filter and the viscous oil.

ACKNOWLEDGEMENTS

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RESEARCH OF THE "ONE-TRIP" GRAVEL PACKING SAND CONTROL SYSTEM FOR STEAM STIMULATION WELLS

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ABSTRACT

A multi-function gravel packing tool was developed by Shengli oilfield for sand control in steam stimulation wells. This tool (Model 7WQ1) was designed to pack gravel with "one trip tubing string," and was able to finish the whole operational procedures in a well. The details of this tool, including the "one-trip" system, shop, and field tests, are discussed in this paper.

In a comparison to the traditional "two-trip tubing string" technique, the new "one-trip" system shows a series of advantages for sand control in steam stimulation wells. These are:

- simplified operation procedures with just one trip to complete the whole gravel packing job;
- the logically designed downhole tool with reliable performance;
- lower operation cost.

INTRODUCTION

The crude in Shanjiashi reservoir of Shengli oilfield is a super-heavy oil with oil viscosity over 10,000 mPa·s, thus it must be produced by steam injection. Unfortunately, the reservoir rock —sandstone— is quite unconsolidated, and sand problems were normally experienced during production cycles. Field practices have proven that gravel packing with wire-wrapped screens was the best way to solve this problem. Thus the studies of gravel packing downhole tool and operation techniques began in 1983. The results of such research and development have progressively been used in the Shanjiashi field, especially the technique with newly designed tools providing reliable foundation for heavy oil recovery by steam stimulation.

Currently, the conventional "two-trip tubing string" method has been used more than 200 times for the gravel pack job in huff-and-puff wells, in which 515 steaming cycles were carried out. The success ratio of sand control was 90.2% with total oil of 2,440,000 tonnes produced. This approach has basically solved sand problems in steam injection wells and achieved satisfactory results. However, this technique can be further improved and replaced by a more advanced "one-trip" method.

The working procedures of the "two-trip" technique (Figure 1) are as follows:

(a) The first trip for gravel packing running in → gravel packing → reverse circulation → tool relieving (from screen) → pulling out of the well.

(b) The second trip for screen/casing isolation with lead seal running in (lead seal string) → linking up (with screen) → relieving → lead seal setting → pulling out the string.

Obviously, the traditional "two-trip" approach must be done by respectively running in two trips of tubing string for gravel packing and lead seal setting. This is to establish an isolative downhole system of gravel/screen as a barrier for sand control. The disadvantages of this technique are: complicated operation procedures, longer working time, and higher costs. Therefore, if a multi-function downhole tool can be developed with only "one-trip" tubing string to accomplish both the gravel/screen placement and the lead seal setting jobs, such a technique would greatly simplify field operation and reduce costs.

MULTI-FUNCTION GRAVEL PACK/LEAD SEAL TOOL

By researching and field testings, a newly designed multi-function downhole tool was developed

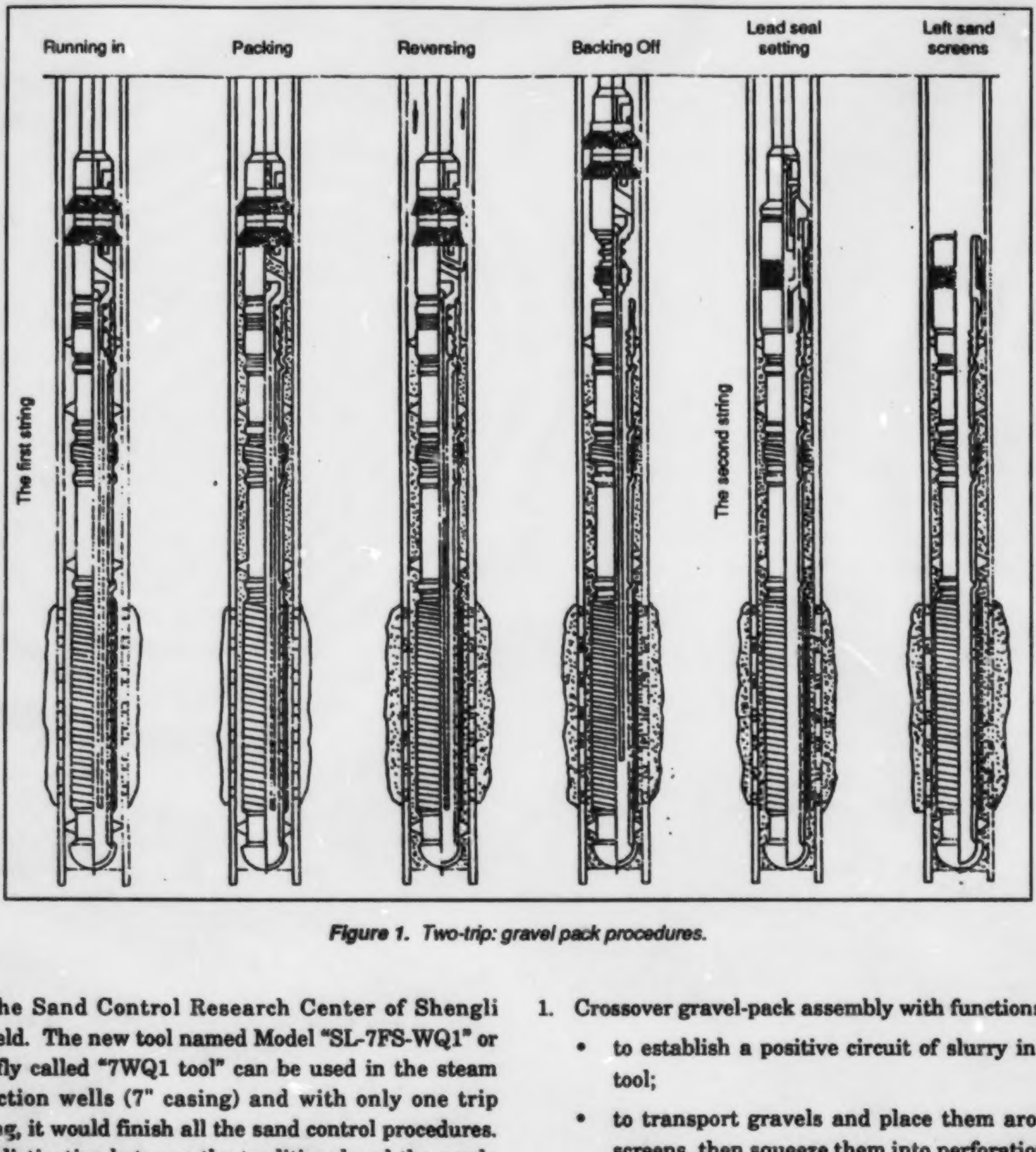
Running in
Packing
Reversing
Backing Off
Lead seal setting
Left sand screens
The first string
The second string

Figure 1. Two-trip: gravel pack procedures.

in the Sand Control Research Center of Shengli oilfield. The new tool named Model "SL-7FS-WQ1" or briefly called "7WQ1 tool" can be used in the steam injection wells (7" casing) and with only one trip string, it would finish all the sand control procedures. For distinction between the traditional and the newly developed tools, the new one is called "one-trip" system.

Basic Structure and Function of New Tool

As shown in Figure 2, the new tool is mainly comprised of four parts as follows:

1. Crossover gravel-pack assembly with functions
    - to establish a positive circuit of slurry in the tool;
    - to transport gravels and place them around screens, then squeeze them into perforations.
2. High-temperature lead seal assembly with functions
    - to accomplish the release of tool from sand screen;
    - to set the lead seal elements for annular isolation.

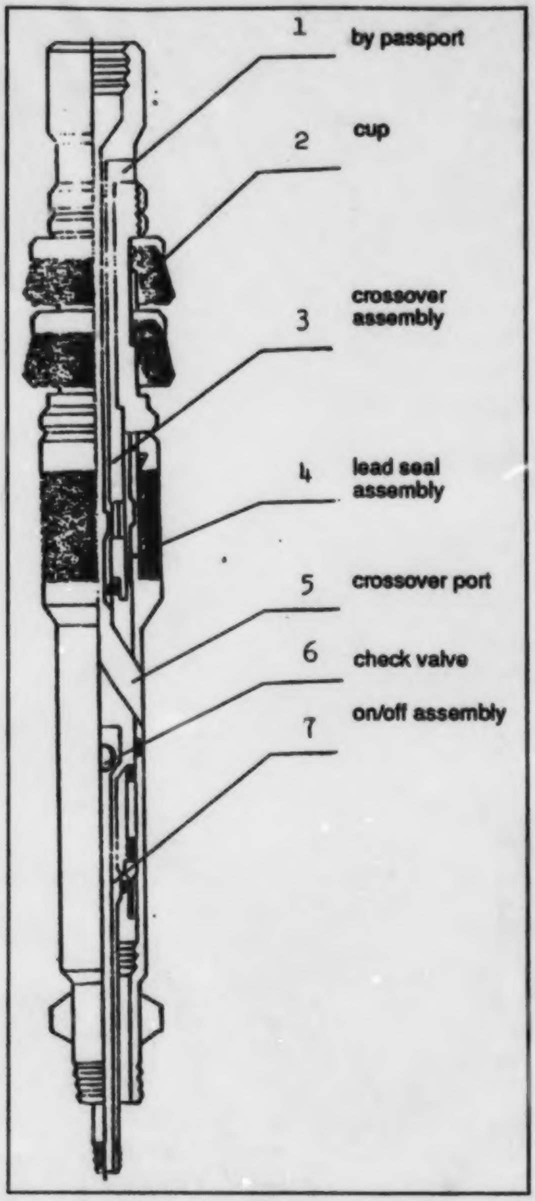

Figure 2. Multi function downhole tool.

3. Crossover port on/off assembly
   - It is a collet-like apparatus. When a job is finished, and the service string is pulled up, it automatically closes up the crossover ports, which were open during gravel packing operation, to establish an isolative downhole filtering system in the wellbore.

4. Bottom chock valve with a function
   - to provide correct liquid circuits in the tool for forward and reverse circulations.

After we detailed tool structure, the working mechanisms from operation procedures (Figure 3) are discussed in follows.

1. Running in
   - run down the tool/screen combination string to the designated location.
2. Forward gravel packing
   - First, pump the no-gravel liquid downhole to establish a forward circulation, making sure all the circulation passages are open. The slurry (or no-gravel liquid) circulation is as follows: service tubing → inside tube of crossover assembly → crossover ports → well annulus (below the cups) → gravel deposition (around the screens) → tailpipe → bottom check valve → the annulus between inside tube and outside tube of the crossover joint → bypass ports → well annulus (above the cups) → wellhead (surface).
   - When the top tell-tale screen is all covered by gravel, a sharp rise in pump pressure will be detected. This indicates sand out, and pumping must be stopped.
3. Reverse circulation
   - This procedure is to displace the extra gravel slurry out from the tubing and to clean up the wellbore. The circulation is as these: tubing/casing annulus (above the cups) → the cups → crossover ports → inside tube of crossover joint → tubing → wellhead (surface).
4. Tool separation from sand screen
   - The pins are sheared out by a hydraulic action to make the tool separated from screens. The service tubing can then be freely pulled up or lowered down. This includes several steps:
     - dropping down a ball in the tubing
     - pumping slowly forward
     - pins sheared out
     - pulling up the string slightly.

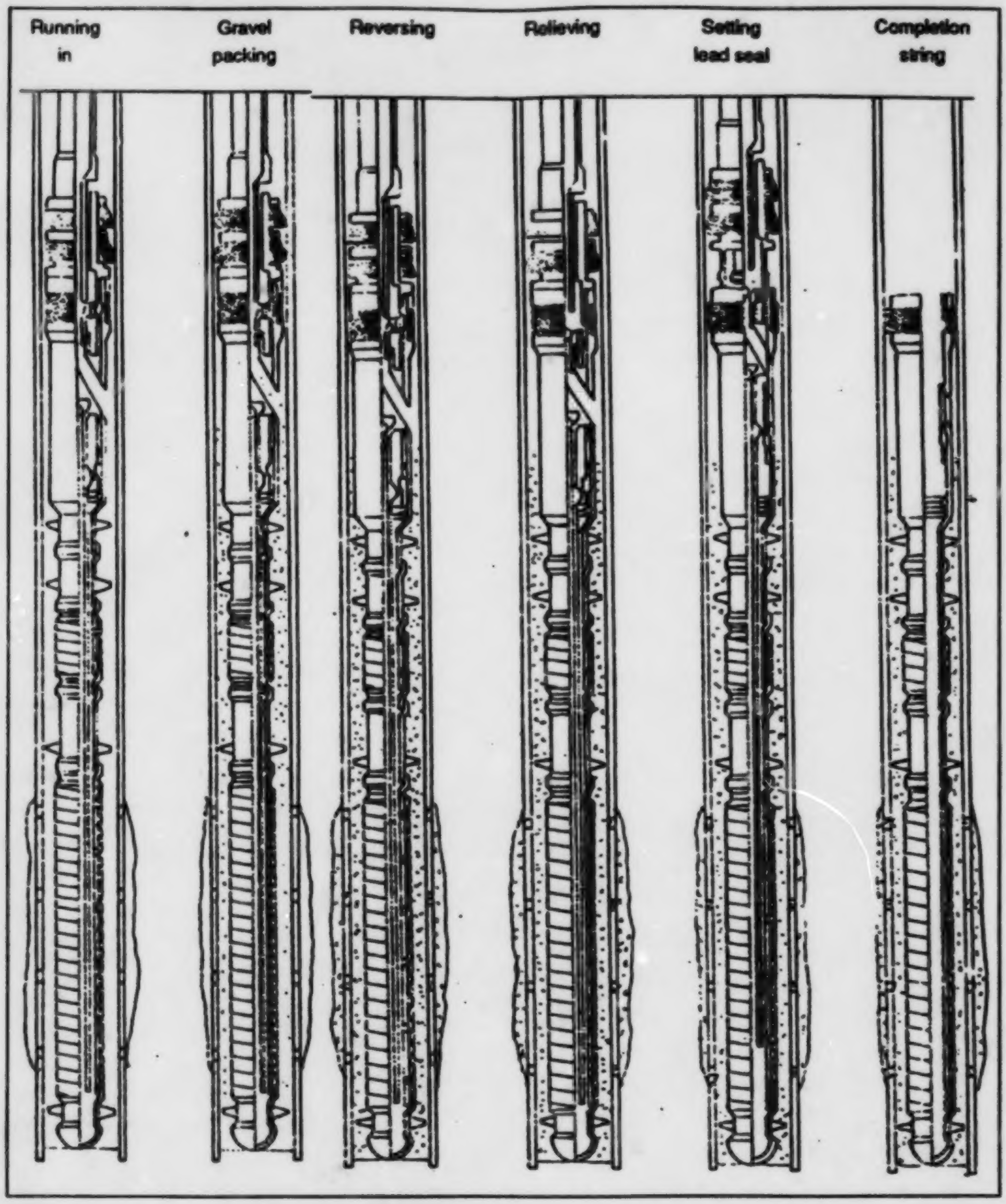
Running in
Gravel packing
Reversing
Relieving
Setting lead seal
Completion string

Figure 3. One-trip: gravel-pack completion procedures.

5. Lead seal setting for annulus isolation
    - This procedure is to pull up the tubing slowly for about one meter, then lower the tubing string makes the seal elements radially inflated.
6. Shutting off crossover ports
    - By pulling up the service tubing, the on/off apparatus drives a sliding sleeve to close up the crossover plots. Continuing pull shears the pins out, then the string would be freely pulled out of the well to end the sand control operation.

Shop Tests for Tool Performance Evaluation

The said tool was comprehensively tested on the surface with simulated downhole conditions to evaluate the working mechanisms, reliability, and to optimize technical parameters for practice. All the shop tests included:

1. Forward squeezing test for the cup (Figure 4, Table 1).

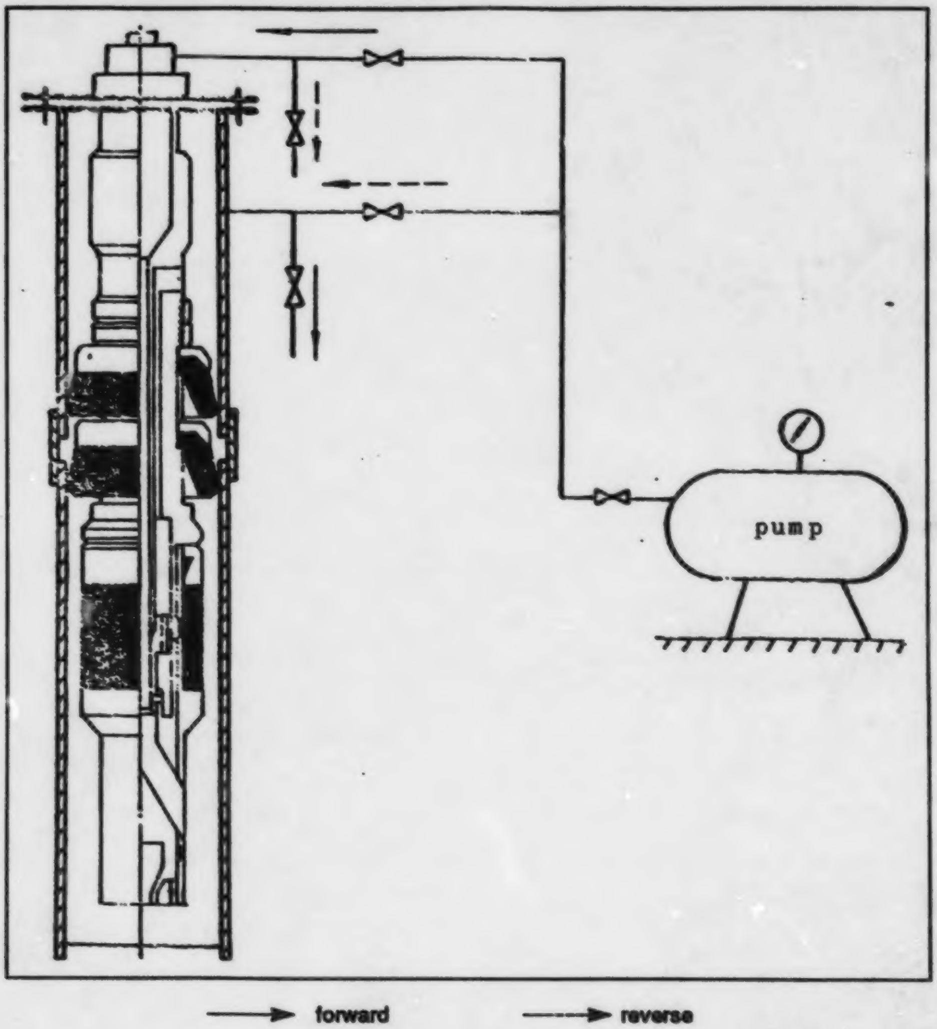

Figure 4. Cup hydraulic test.

Table 1. Cup hydraulic test results

Casing I.D. mm	Cup O.D. mm	Test material	Squeeze sealing pressure MPa	Reversing P 100,000 Pa
159.4/160.5	166	water	25	0.7–0.8
157.08	161	water	25	0.6

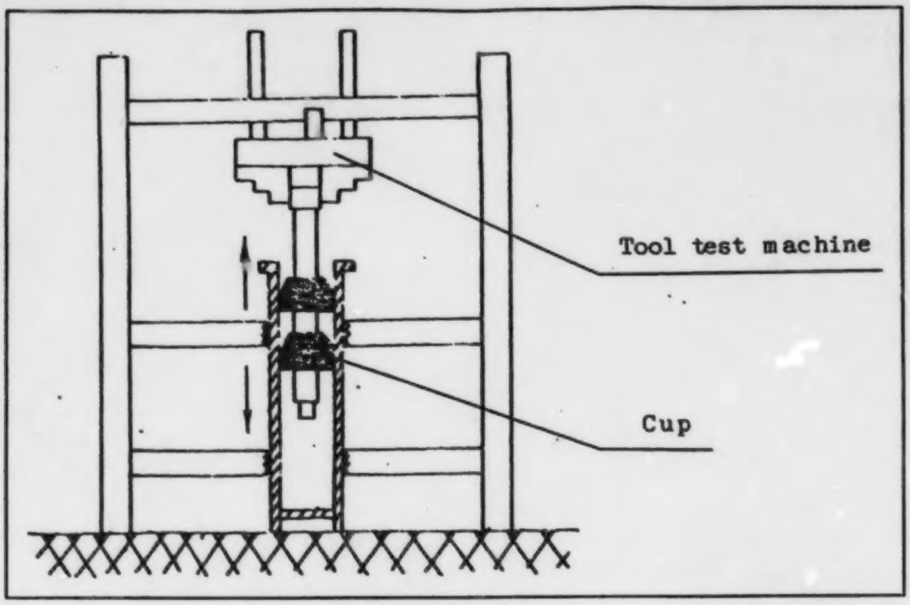

Figure 5. Cup friction test.

Table 2. Cup friction measurement

Casing I.D. mm	Cup O.D. mm	Friction (up) N	Friction (down) N	Note
159.4/160.4	166	595	885	Measure at time when cup move
157.08	161	546	824	

2. Measuring pressure differential at the cup for reversing circulation (Figure 4, Table 1).
3. Up and down cup friction tests (Figure 5, Table 2).
4. Hydraulic separation test for the tool (Figure 6, Table 3).
5. Lead seal setting test (Figure 7, Table 4).
6. Self-lock test of the lead seal (Figure 8, Table 5).
7. Crossover port on/off test (Table 6).

The experimental results are all listed in Tables 1 to 6, which indicate that tool design is logical, performance is reliable and meets with the need for "one-trip" gravel packing in the steam injection wells.

FIELD TESTS AND RESULTS

Since October 1988, 14 sand-control completions have been accomplished by using "one trip" gravel packing technique. All the operating procedures and corresponding technical parameters based on the field tests are established.

1. Operation procedures (Figure 3). The operating parameters are listed in Table 7.
    - The operation procedures can be figured out from the tool function as follows: running → forward circulating → gravel packing/ displacing → reversing → hydraulic separating → lead seal setting → pulling up and closing crossover ports → pulling out.

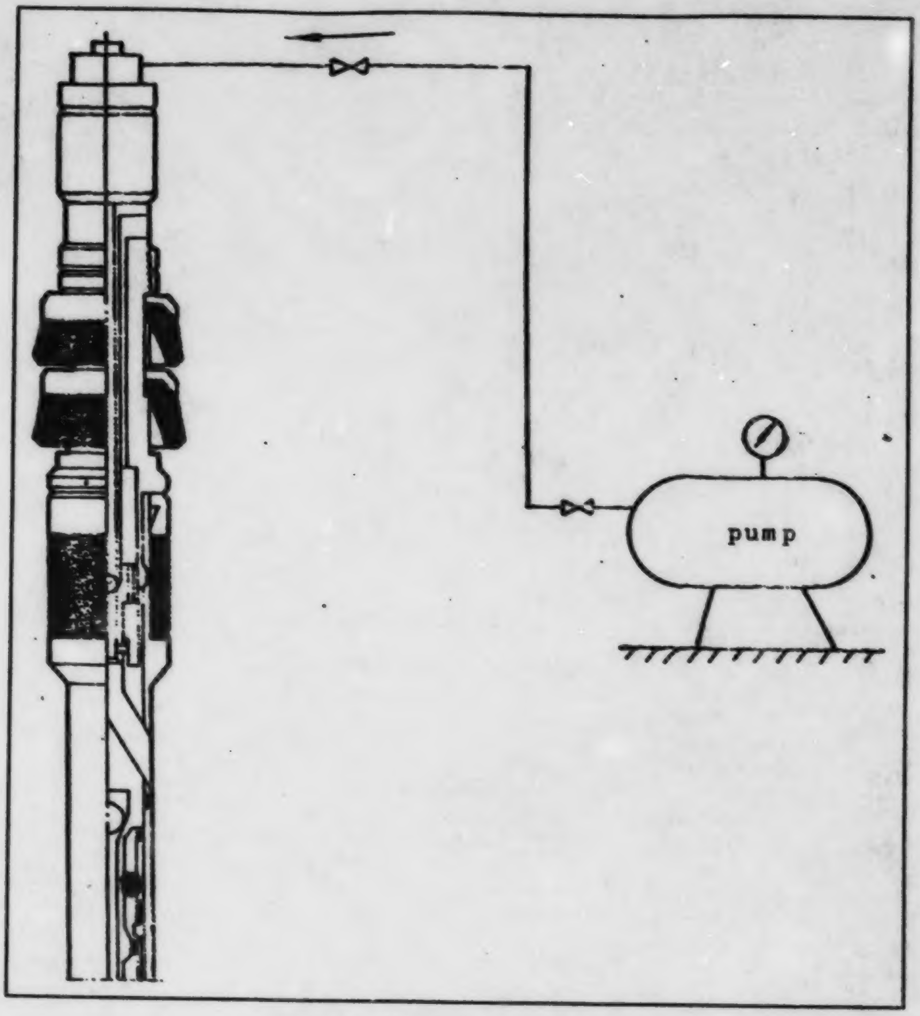

Figure 6. Hydraulic separation test.

Table 3. Tool hydraulic separation test

Pins			**Pressure for shearing out MPa**	**Note**
Size mm	**Material**	**Number**		
M8 x10	brass	4	28	When pins were sheared out, up or down movement could be seen
M8 x10	brass	2	15	
M6 x 8	brass	2	9	
M6 x 6	brass	3	12	

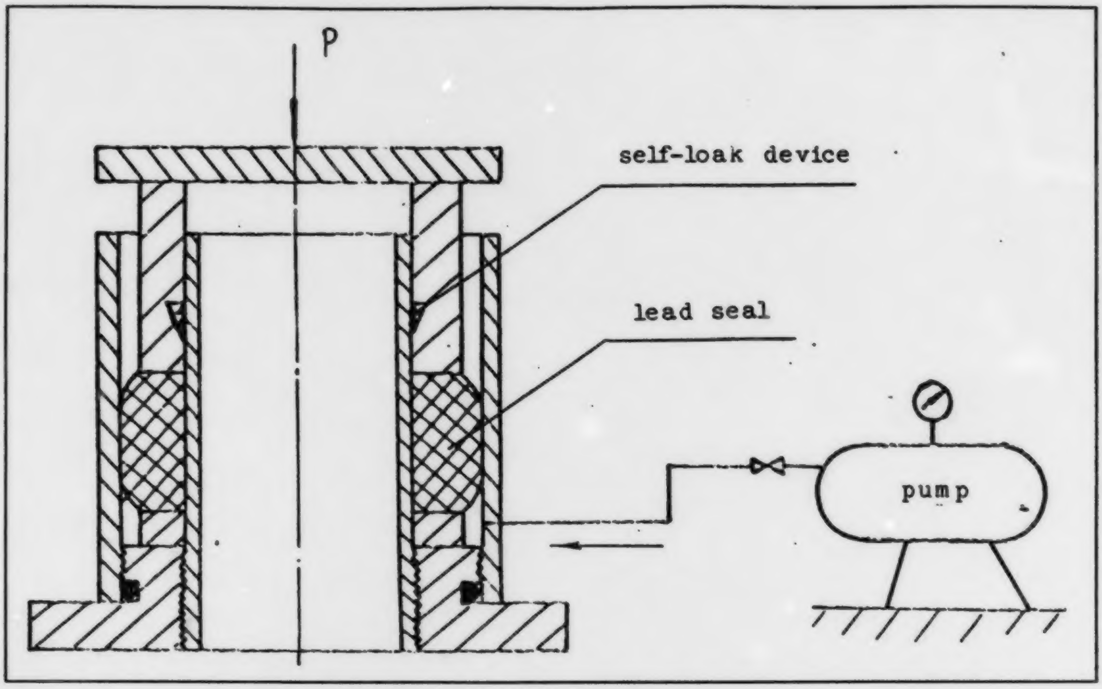

Figure 7. Lead seal setting test.

Table 4. Sealing element test

Material	Dimensions D x d x h mm	Setting parameter		Sealing perform		Temp. °C	Note
		Stroke mm	Load KN	Test media	Sealing press Mpa		
Soften graphite	160 x 126 x 145	30	≥25	water	5.0	350	No leak

2. Results of sand control
   - Using "one-trip" technique for thermal well completion, 13 jobs were successfully done. Only one failed due to a broken screen. For these 13 comparable wells, the success ratio for both operation and sand control was 100% without any failure directly related to tool malfunction.
   - The percentage of gravel-pack averaged 117.3% in the said wells, and met the expectation of the tool design. After the completions, these wells were progressively put on huff-and-puff steam injection at the following conditions:
     - period of injection cycle: 6–14 days
     - average total steam injection: 3,640 tonnes
     - steam temperature: 288–348°C
     - steam pressure: 7.16–17.3 MPa
     - injection rate: 5.9–24.2 tons/h
     - steam quality: 56.0–71.9%
   - At present, we have 21 steaming cycles on 13 completed wells with sand control. Some wells are still operating. So far 66,400 tonnes of oil and more than 33,600 tonnes of water have been produced.

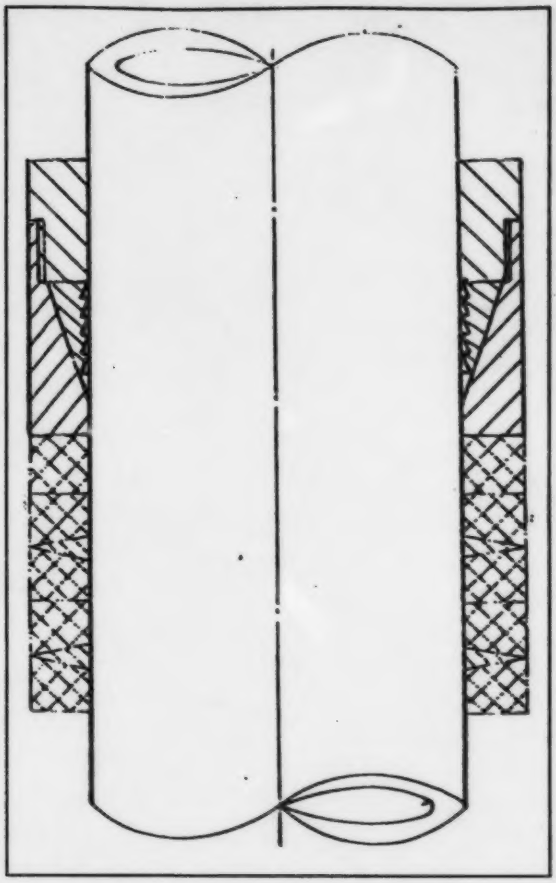

Figure 8. Lead seal self-locking test.

- 5 wells with high water cut ranging from 97 to 100% have been shut in. The other 8 wells are still producing regularly. The reservoir and production data from these wells are:
  - average net pay: 12.2 m
  - daily oil rate: 36.8 tonnes
  - daily total liquids: 93.7 tonnes
  - production strength: 7.7 tonnes of daily total liquids/m
  - continually effective production: 247 days
  - sand content in weight ratio at wellhead: 0.03%
  - average oil production per cycle: 7,681 tonnes
  - average oil/steam ratio per cycle: 2.12

As the data shown above, the production performance from these wells, which were completed by using the "one-trip" gravel-pack technique, was quite satisfactory. It is believed this technique will be extensively used in the oilfields.

CONCLUSIONS

Through the shop tests of the 7WQ1 multi-function tool, the field practice of the "one-trip" technique, and the actual production performance

Table 5. Self-locking test

Self-lock manner	Design fric. angle degree	Theoretical self-lock angle degree	Self-lock condition	Sealing press. Mpa
Frictional	7	8.5	When pulling at 110 KN of force, it was kept locked.	5.0

Table 6. Crossover ports on/off test

			Sealing element		
Friction (up) N	Friction (down) N	On/off performance	Material	Temperature °C	Pressure Mpa
1000	2400	Free movement up and down	Soften graphite	>350	5.0

*Table 7. "One-trip" system technical parameter **

Type of gravel pack	Low density circulation	High density squeeze
Viscosity of carrier fluid, MPa·s	30–40 or less	300–400
Volumetric ratio (gravel/liquid)	(510)/100	(80–100)/100
Pumping rate, L/min	400–500	320
Maximum pumping press, MPa	10–12	14–16
Reversing rate, L/min	over 500	over 500
Relieving press., Mpa	about 12	about 12
Lead seal setting load, KN	>25	>25

* For wells with depth less than 1500 m.

from the sand controlled wells, all indicates the tool performed very well. Since the said technique quite simplified field operation with attractive success ratio for sand control in the steam injection wells, the expectation of this tool's function is entirely satisfied.

To sum up, the "one-trip" gravel packing approach developed by the Shengli oilfield for steam huff-and-puff wells has achieved great success. The technical advantages of using this tool are:

1. The "one-trip" system using multi-function downhole tool could replace the traditional "two-trip" system for steaming/sand control completions. Since the former was developed with advanced technology, it will simplify field operations and accomplish a high success ratio in well completions.
2. The new tool can be separated from the sand screens by using hydraulic action, which is much easier in control than the way of traditional "back-off". The hydraulic approach is more secure in making precise surface judgement of tool separation. From field practice, this showed a 100% separation success. The said approach is also favorable for sand control in the deviated holes.
3. Two different kinds of sealing materials, oil-resisting rubber and soften graphite, were used in the 7WQ1 tool. These materials could meet the need for pressure seal in the low and high temperature conditions.
4. When pulling up the service string after the lead seal was set, the crossover ports in the tool would be automatically closed up by a special on/off apparatus. So far, the success ratio of this operation has been 100%.
5. The self-lock condition, after lead seal was set, was excellent, since its frictional self-lock (with more than 11 KN of locking force) could make permanent annulus isolation at high temperature.
6. The cost of sand-control completion by using "one-trip" method was reduced of about 5,000 (RMB) compared to that of using the traditional "two-trip" technique. This is because of omitting the one trip of running and pulling string time in the former operation.

Based on the above mentioned advantages, the "one-trip" approach will become popular for sand control in steam stimulation wells, and will play a more important role in enhanced oil recovery.

ACKNOWLEDGEMENTS

The authors express appreciation to the management of the Shengli oilfield for permission to publish this paper, and for their encouragement and support.

Appreciation is also expressed to W.X. Wang; W. Wang; J. Qu; and Y.Q. Zhang for their development of this new system.

In Situ Monitoring Instrumentation at AOSTRA's Underground Test Facility

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ABSTRACT

The Alberta Oil Sands Technology and Research Authority has been conducting thermal in situ bitumen recovery tests at the Underground Test Facility (UTF), northwest of Fort McMurray, Alberta, Canada, since November, 1987. One of the processes being studied at the UTF is Steam Assisted Gravity Drainage (SAGD). The SAGD process uses horizontal wells drilled in pairs from an underground mine. As part of the project, 28 vertical observation wells, drilled from surface, were installed to monitor the growth of the steam zone. Instrumentation in these wells includes thermocouples, piezometers, extensometers, and inclinometers. Thermocouples were also installed in three of the six horizontal wells. More recently, passive seismic monitoring has been investigated and cross hole seismic tomography is planned for Phase B of the project. This paper discusses the success of the instrumentation to date, including attrition, improvements to the designs and installation techniques, and the Phase B in situ monitoring program.

THE UTF

The Alberta Oil Sands Technology and Research Authority (AOSTRA) has been testing two in situ recovery processes since November, 1987 at the Underground Test Facility (UTF), 70 km northwest of Fort McMurray, Alberta, Canada. The horizontal recovery processes are: Steam Assisted Gravity Drainage (SAGD) and Chevron's patented Heated Annulus Steam Drive (HASDrive) process. Various papers describe the UTF (1), the geology (2), the SAGD process (3), and the HASDrive process (4). A summary is provided herein.

The UTF site is located in the Athabasca Oil Sands deposit in northeast Alberta, Canada, as shown in Figure 1. At present the facility consists of a 25 MMBTU/hr. steam generator, production handling facilities (bitumen and water are not separated), two 225 m shafts 3 m in diameter, approximately 1500 m

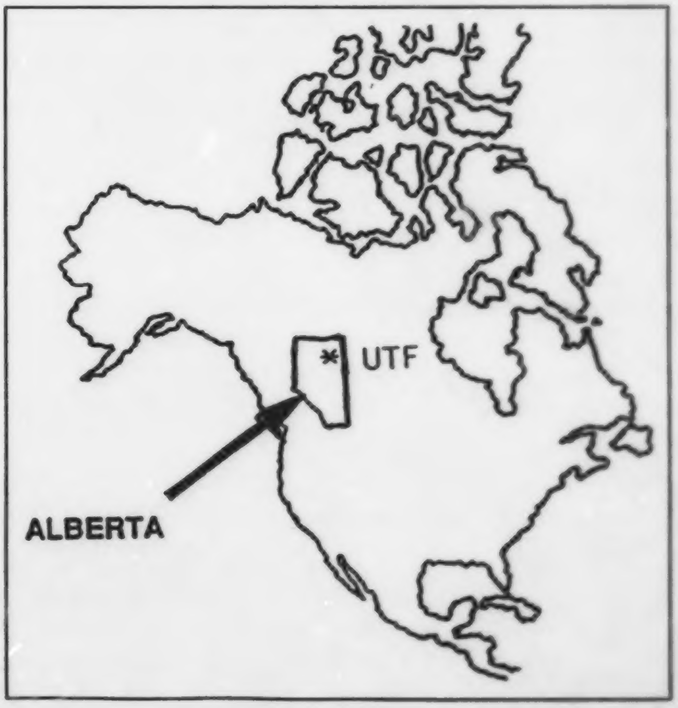

Figure 1. UTF location map.

of tunnels, three pairs of SAGD wells with three more pairs planned for the second half of 1990 and one HASDrive test. There are also facilities to support the operation of the mine and surface facilities.

Phase A geology, as shown in Figure 2, consists of approximately 20 m of exploitable oil sands. Generally, the reservoir is rich and clean in the bottom half and more shaley and interbedded in the upper half. The shale break (Unit F) shown in Figure 2 is predominantly a silty sand and is not consistent with the Phase B test area and most of the commercially identified UTF lease.

A schematic of the Phase A SAGD wells is shown in Figure 3. The horizontal wells are drilled from the mine tunnels, upwards and along the base of the oil sands. The production wells were drilled low in the reservoir with the injection wells 3 m to 5 m above. Injection pressures are maintained below fracture pressure and production is controlled with a steam trap control, producing fluid just below steam saturation conditions. The result is very efficient use of steam while withdrawing the maximum amount of steam-free fluids (Edmunds).[3] The observation well layout for the Phase A operation is shown in Figure 4. The layout consists of 26 thermal wells and two baseline pressure wells, to monitor temperature (8 wells), pressure (6), temperature and pressure (5), horizontal displacement and temperature (6), and vertical displacement of the oil sands (3).

Steaming of the Phase A pilot began in early December, 1987. Monitoring data has been collected continually for approximately two years. Phase A set out to examine two primary unknowns: the horizontal well completion requirements and the effect of geology on the recovery process, particularly vertical heat rise rates.

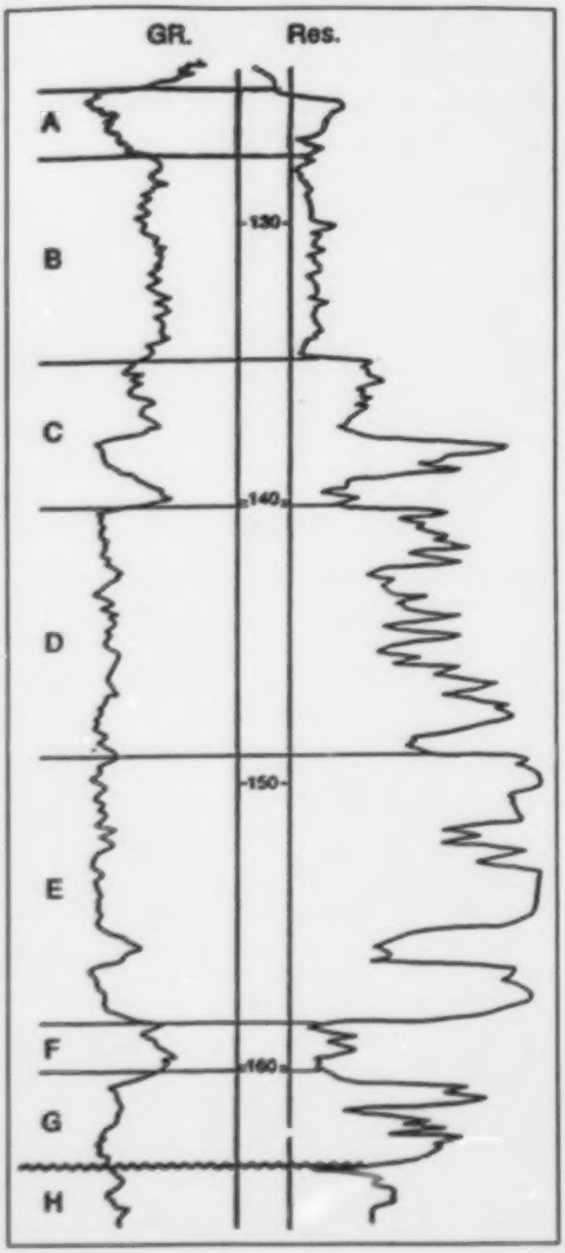

Figure 2. Typical UTF Phase A geology.

MONITORING PHILOSOPHY AND OBJECTIVES

Other than the thermocouples, the monitoring instrumentation used at the Phase A site had not previously been installed for operation at the depths and temperatures required by AOSTRA. Piezometers and extensometers were installed at depths between 125–165 m in an environment where temperatures would exceed 225°C. Inclinometer wells were only expected to move 15 mm, requiring accurate slope measurements at depths considerably deeper than the depth that standard inclinometer equipment allows for and at temperatures much higher than normally experienced by inclinometer survey tools.

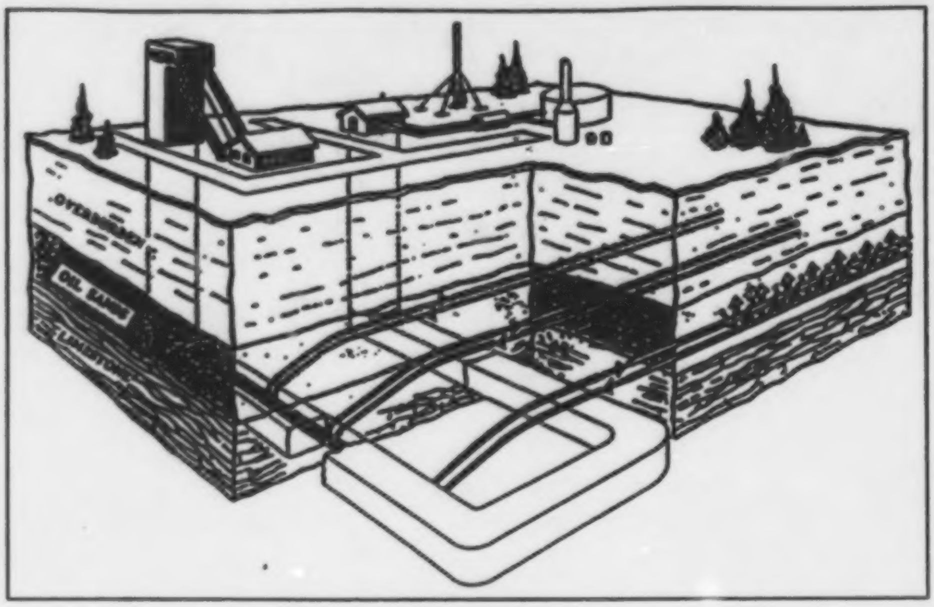

Figure 3. UTF schematic.

Because of the novel nature of the desired in situ measurements, a degree of duplication and conservatism was applied to the piezometer and extensometer design to ensure that reliable data would be obtained. The primary objective of the UTF monitoring instrumentation was to monitor the response of the recovery process and the specific objectives were to:

1. Determine the initial in situ temperatures, pore pressures and stress state in the Clearwater, McMurray and Waterways Formations.
2. Monitor the temperature, and pore pressure changes, and the compressive and shear deformations in the Clearwater and McMurray Formations in and surrounding the Phase A pattern.
3. Monitor the temperature changes in and surrounding the HASDrive steam chamber.
4. Monitor the integrity of the shafts and tunnels of the UTF.
5. Monitor the integrity of the horizontal process well completions.
6. Investigate and report on the performance of the monitoring instrumentation and develop cost effective instrumentation designs for future installations.
7. Determine how the geomechanical responses of the formation affect bitumen recovery processes, in particular the SAGD process, in a large scale pilot or a commercial operation, and to determine what instrumentation was best suited to monitor these responses.
8. Determine the cost effectiveness of a monitoring program.
9. Assemble a database of geomechanical responses to the in situ recovery processes which can be applied to future UTF expansions and other projects.

PHASE A INSTRUMENTATION

Phase A observation wells (Figure 4) can be split into two groups: the temperature monitoring wells above the horizontal process wells and the temperature, pressure, and formation movement wells across the middle of the pattern.

The temperature monitoring wells above the horizontal wells are used primarily to monitor steam rise rates in the reservoir. Analytical and numerical simulation studies identified vertical steam rise in the reservoir as a controlling parameter that would affect the economic viability of the SAGD process. Most other important parameters could be readily obtained, but the effective vertical permeability needed to be correlated with in situ measurement of steam rise rates, could not be obtained accurately. This in situ correlation was required because the interbedded, discontinuous sands and shalier

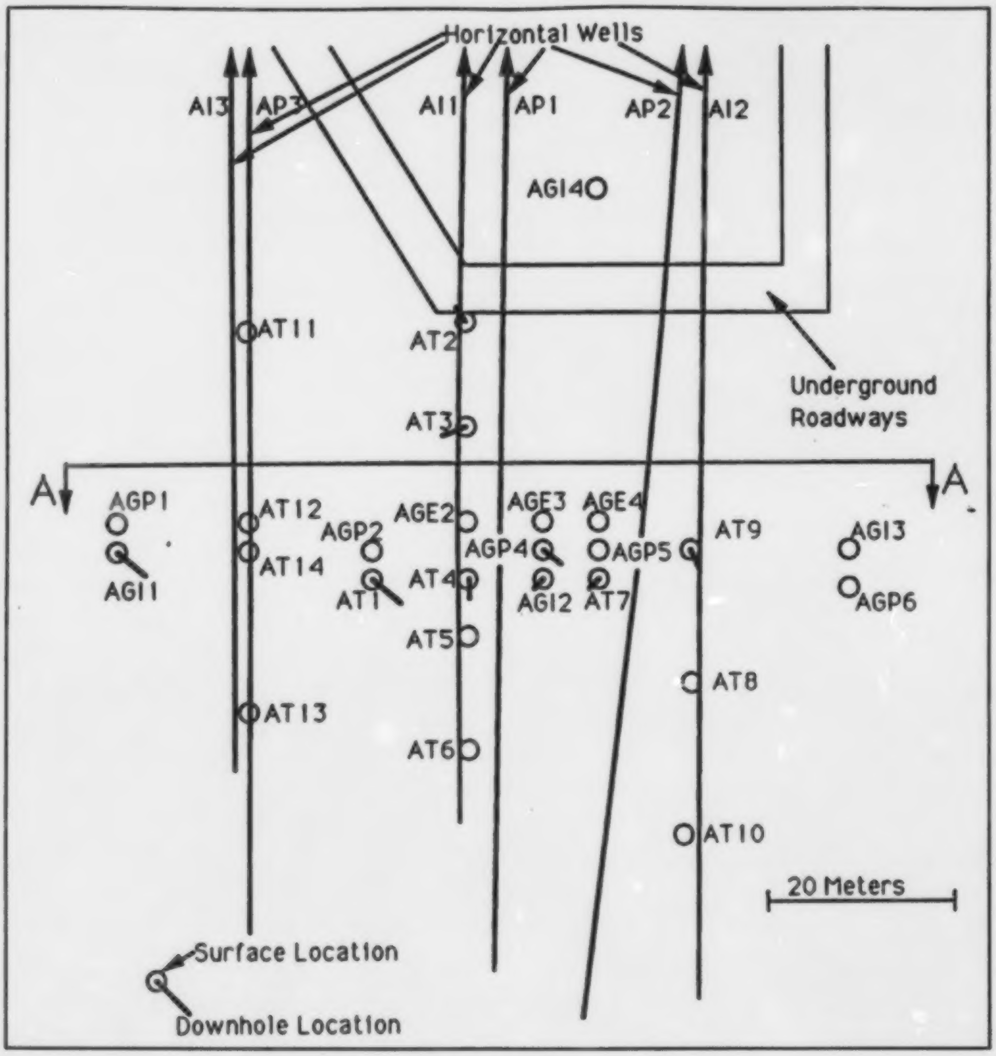
Horizontal Wells
AI3
AP3
AI1
AP1
AP2
AI2
AGI4
AT11
AT2
AT3
Underground Roadways
A
A
AGP1
AGI1
AT12
AT14
AGP2
AT1
AGE2
AT4
AGE3
AGE4
AGP4
AGP5
AGI2
AT7
AT9
AGI3
AGP6
AT5
AT8
AT13
AT6
AT10
20 Meters
Surface Location
Downhole Location

Figure 4. UTF Phase A geotechnical well plot plan.

stringers created a heterogeneous reservoir that precluded the direct application of permeabilities obtained from core analysis.

Wells shown in Figure 5 measure temperature, pressure, and horizontal and vertical displacements across the Phase A pattern. Temperature and pressure data is obtained from all eight geotechnical well eastings shown on the section. Horizontal and vertical formation movements are obtained at five and three of the eastings, respectively. The number of extensometer installations was limited because of the high cost and unknown reliability.

Thermocouples

Because of limited industry experience in cementing multipoint thermocouples bundles, it was decided to drill and case as many of the observation wells as possible. Where possible the monitoring wells were sumped into the limestone below the oil sands. However, for fear of drilling into the horizontal wells, the monitoring wells were drilled to 2 m above the horizontal injection wells and cased. A stab-in cementing technique was used which resulted in approximately 1.0 m of cement in the bottom of the casing and float shoe. It was felt this would be a

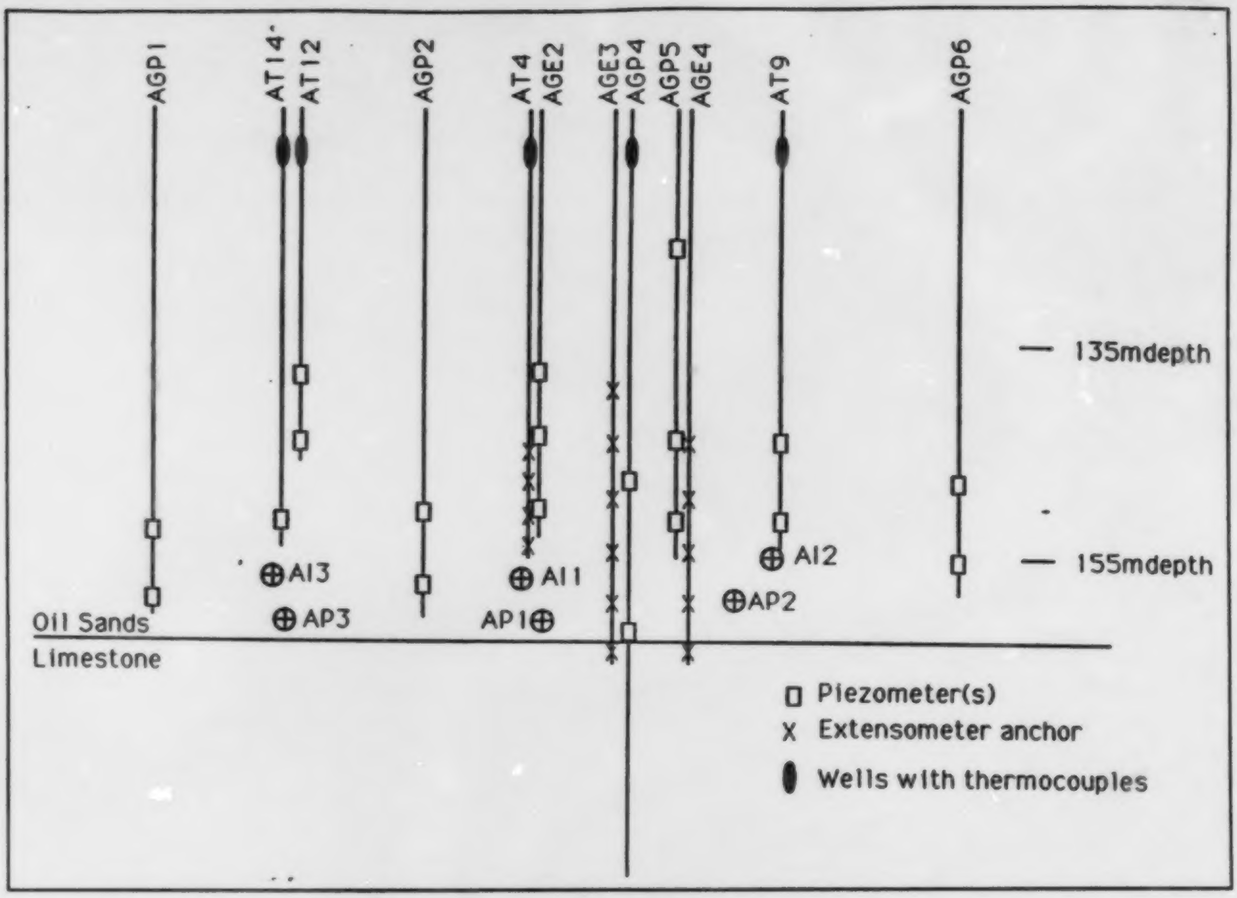

Figure 5. Geotechnical instrumentation cross section.

sufficient seal to stop reservoir fluids from entering the well. This proved to be true until local flashing was observed when temperatures exceeded 100°C. The thermocouples were subsequently cemented in place, in the casing, using endless tubing.

Thermocouple bundles were constructed with type E316 SS metal sheathed wire for the reservoir section with a less expensive flexible plastic coated extension cable above the expected hot zone, running to surface. The thermocouple bundle design was based largely on an AOSTRA instrumentation review by Wong[5] and discussions with suppliers. As of January, 1990, 233 of the 239 installed thermocouples were functioning. No problems have been experienced with the multipoint thermocouple bundles cemented in place. These favorable results agree with those reported by Gronseth[6] noting that the thermocouples run by ESSO were metal sheathed to surface and the multipoint bundles at the UTF have a transition to a flexible extension cable above the steam chamber. To ensure that accurate temperature readings are obtained from the cased observation wells, the holes were kept dry. Any moisture in the wells within the heated reservoir would result in refluxing and flashing, thereby distorting the temperature profile. Griston[7] indicates the importance of keeping the well dry, particularly for situations with sharp temperature gradients. Temperature gradients greater than 50°C/m are common at the UTF.

Extensive use of traversing multi-point thermocouple bundles has provided for detailed temperature surveys. The bundles, which are hung over a raised sheave, can be lowered or raised from their baseline position. The main advantage of the multipoint profiles, verses single point surveys, is the consistent baseline elevation. This profiler has proved very effective and is included in the Phase B monitoring program, although the distribution of the thermocouple endpoints in the Phase B wells is designed to minimize field handling.

Piezometers

Pneumatic and vibrating wire piezometers are used for pressure monitoring with a rated precision of ±15 kPa at all points of installation. The measurements were accurate enough to measure the initial hydraulic pressure gradient in the reservoir. Following installation, pneumatic and vibrating wire piezometers were in close agreement. This initial close agreement between pressure readings from the two types of piezometers was not maintained as pressures increased, as shown in Figure 6. This is due to a temperature calibration which needs to be applied to the vibrating wire piezometers. The temperature could not be obtained due to temperature sensor failure in the piezometer.

For the thermal installations the two types of piezometers were installed in pairs. This duplication was used due to the depth of installation and the consequent uncertainty of the new installation technique employed and the aggressive environment in which the instruments were to operate. Following installation, one vibrating wire piezometer and one pneumatic piezometer were nonfunctional. Both types of piezometers generally worked well until they were contacted by steam, after which most units would fail. As of January, 1990, 4 of 19 high temperature vibrating wire piezometers were functioning, 10 of 19 high temperature pneumatic piezometers were functioning and 4 of 6 baseline vibrating wire piezometers were functioning. Generally, the vibrating wire piezometers failed first, followed by the pneumatic units. Fluid leakage into the units is the suspected problem. Modifications to prevent fluid leakage into the piezometers are required and are discussed later in this paper. One of the failed pneumatic piezometers was successfully converted to a bubble tube.

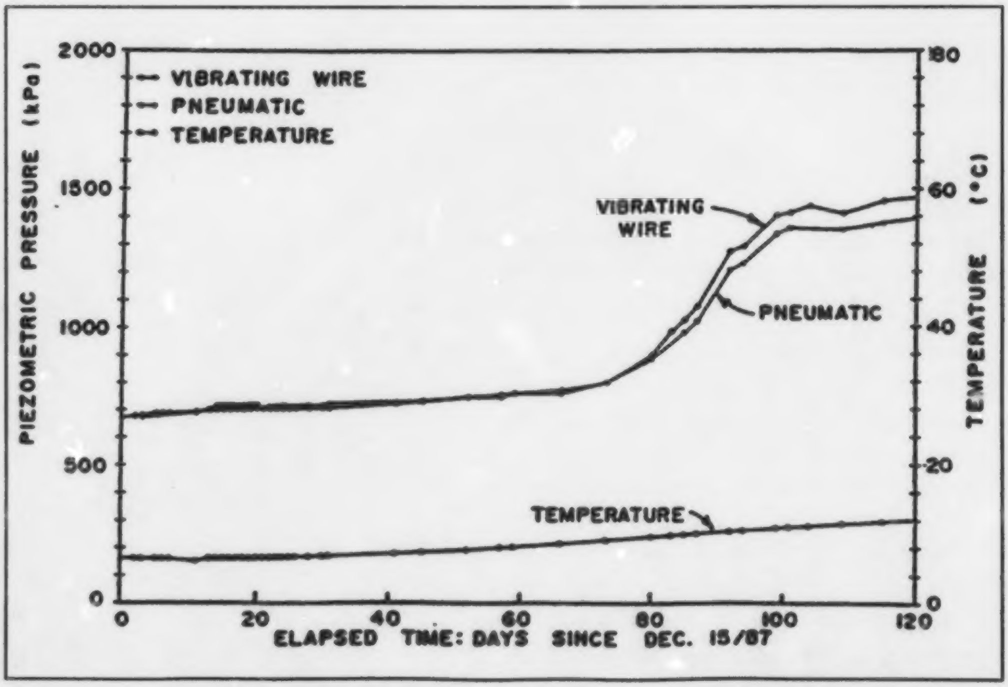

Figure 6. Sample of "nested" piezometer readings.

For economy, pressure measurement at multiple elevations in each observation well was desirable. To achieve this, piezometer "nests" were cemented in open holes. Six piezometers was the maximum number attempted in a single well. The maximum number of units installed in a single well is limited by the number of wires which can be accommodated in the well. For the hole configurations used in Phase A, the maximum number of piezometers in a single well would be 8–10 units if a thermocouple bundle were also installed. Pressure data indicated good hydraulic isolation between piezometers located at different elevations in the same well, a result of a good cement job and the impermeable nature of cold oil sands.

The Phase A piezometer well design is shown in Figure 7. This modification will save considerable time and expense. To ensure a positive contact with the reservoir, a piezometer "actuator" was used (Figure 8). The piezometers were mounted in a permeable epoxy sand mixture in one of the trays. The actuator was then mounted on a 25 mm installation pipe and run into the well. To set the actuator, a wireline "shearing" bar was run down the inside of the pipe, shearing the wires holding the trays to the pipe. The springs forced the trays against the hole wall holding them in place. The hole was then cemented by injecting cement down the pipe and up the annulus. Following installation, the piezometers measured the cement column hydrostatic head, followed, in about 2 days, by the expected initial reservoir pressure. This installation technique proved very effective and is included in Phase B. In the Phase B installations the surface casing, installed to 130m, was not used because of the favorable hole stability at the UTF site.

Piezometers were also installed on the outside of one cased well in Phase B, embedded in a sand-pack filter without using actuators. These filters were water saturated prior to their installation and the subsequent cementing has not impeded their performance.

Resistance Temperature Devices (RTD's) were installed as part of the Phase A vibrating wire piezometers. Many of these failed prior to experiencing steam temperatures and all RTD's subjected to steam temperatures failed.

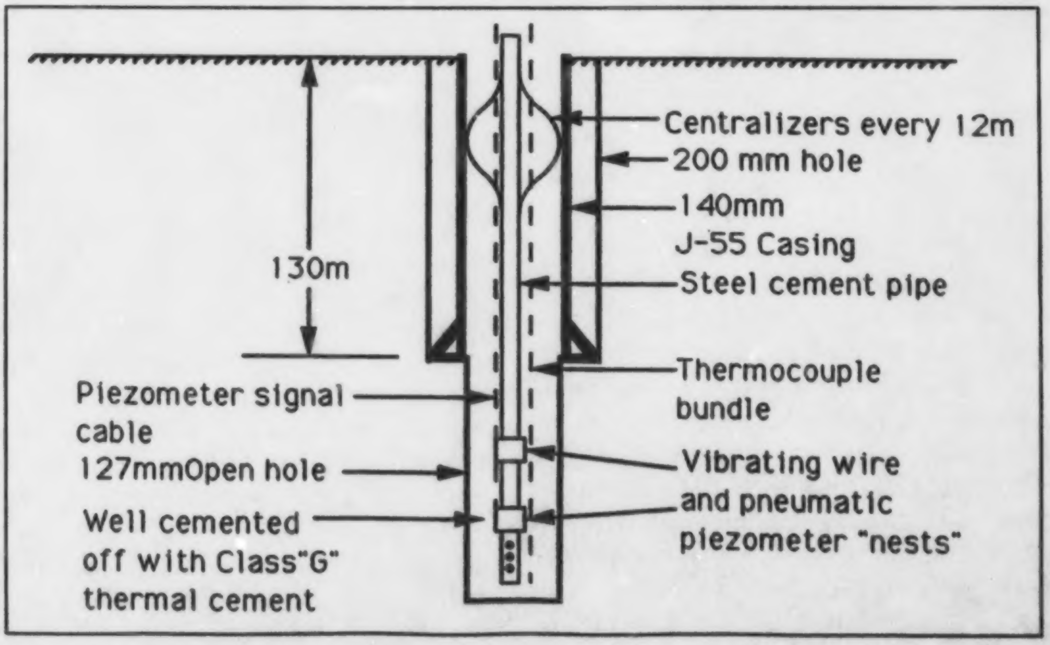

Figure 7. Phase A piezometer well design.

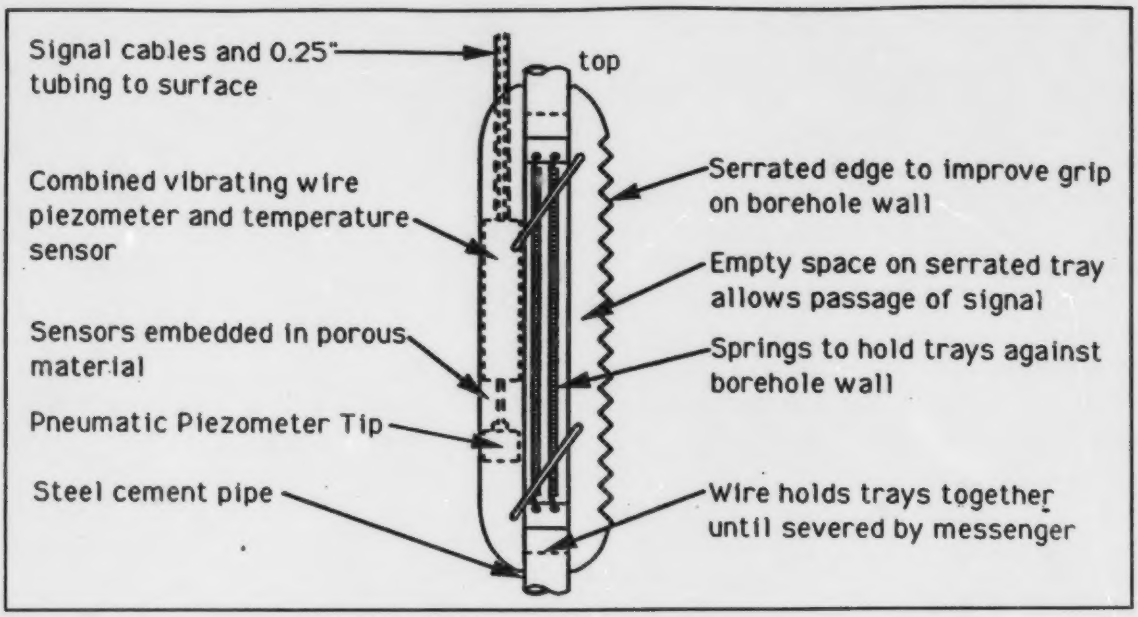
Signal cables and 0.25" tubing to surface
top
Combined vibrating wire piezometer and temperature sensor
Serrated edge to improve grip on borehole wall
Empty space on serrated tray allows passage of signal
Sensors embedded in porous material
Springs to hold trays against borehole wall
Pneumatic Piezometer Tip
Steel cement pipe
Wire holds trays together until severed by messenger

Figure 8. Piezometer actuator.

In addition to the high temperature piezometers located in and around the Phase A area, two low temperature piezometer wells were installed 200 and 525 m from the test area. After two years of operation, no significant pressure variation has been detected in either of these wells.

Extensometers

High temperature extensometers were installed in three wells (Figure 9) to measure vertical deformation of the oil sands due to thermal expansion, dilation, and compression. Modules consist of an invar rod (low coefficient of thermal expansion) 3 m or 5 m long with an LVDT (Linear Variable Differential Transformer) to measure extension and compression. Each module was anchored at either end to hold it in place. Up to six modules were successfully installed in an individual well. As with the piezometer installations, surface casing was cemented to 130 m. The extensometers were cemented in the uncased portion of the hole from depths of 140 to 165 m.

Extensometer installations were much more difficult than piezometer installation because the steel cementing pipe, used to install the piezometers, could not be left in the same interval of the extensometers without affecting the expansion readings. Therefore, the extensometers were installed by lowering them on a cable beside a retractable cement pipe. The hole was cemented and the pipe was pulled clear of the extensometers.

Success with the extensometers at high temperatures has been limited. Leaks in the LVDT's have periodically caused erroneous readings, although some useful data has been collected. Some of the problems encountered are a result of the deformations being more than expected. Bead thermistors were incorporated in these units, however, these were unreliable and all failed prior to being exposed to steam. Only one extensometer well is included in Phase B because of the limited success in Phase A and the high cost of the instruments. The extensometer for Phase B was included to examine the vertical deformations of the larger pattern, which should have reduced boundary effects, and to confirm the data gathered in Phase A.

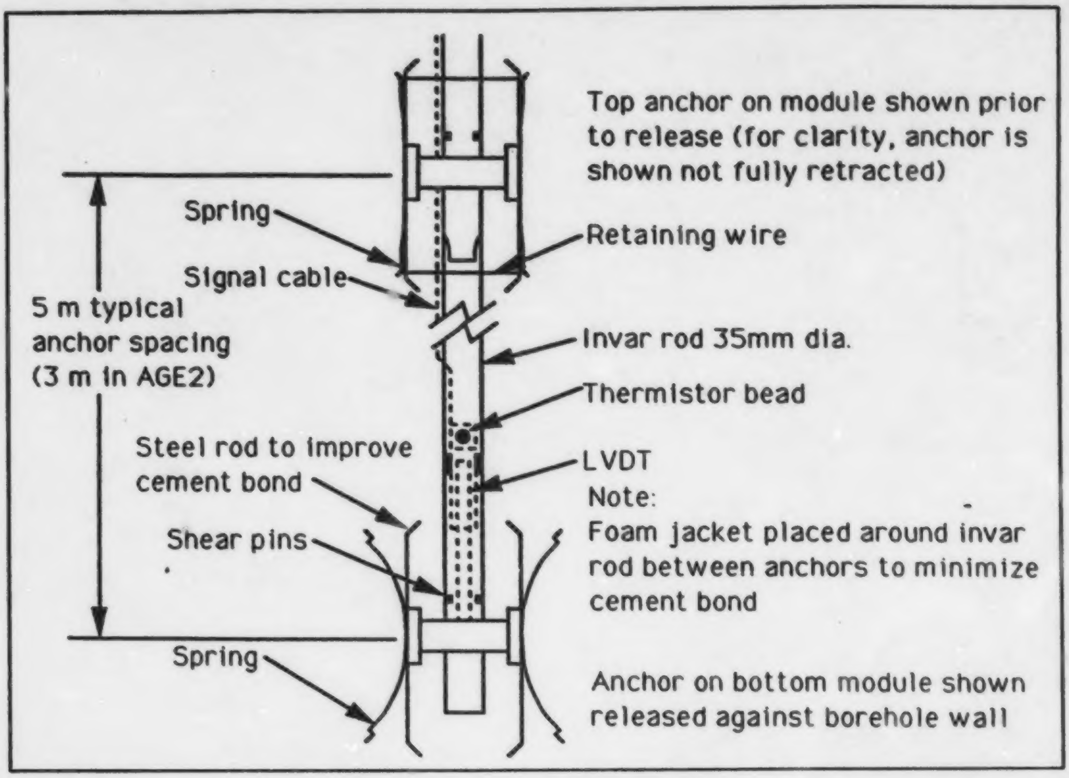
Top anchor on module shown prior to release (for clarity, anchor is shown not fully retracted)
Spring
Retaining wire
Signal cable
5 m typical anchor spacing (3 m in AGE2)
Invar rod 35mm dia.
Thermistor bead
Steel rod to improve cement bond
LVDT
Note:
Foam jacket placed around invar rod between anchors to minimize cement bond
Shear pins
Spring
Anchor on bottom module shown released against borehole wall

Figure 9. Cemented extensometer module.

Inclinometer Surveys

To measure horizontal reservoir displacement, a commercial rate gyro was used to survey a 45m interval through the reservoir and into the underlying limestone. The gyro operates in standard open cased wells. An insulating shield installed over the gyro protects it from elevated well temperatures. Two initial surveys run in one well showed a repeatability of 1 mm over the 45 m interval surveyed. As a maximum deflection of 15 mm was anticipated, this accuracy was believed sufficient to analyze the data. Subsequent surveys proved not to be as accurate as the initial survey check indicated. This was attributed to variations in the gyro calibration. To overcome this, data has been analyzed by zeroing both ends of the surveys, as shown in Figure 10. Results obtained and analyzed in this fashion have been accurate enough to predict reservoir heating based solely on the inclinometer data.

Passive Seismic

Micro-seismic events of short duration are associated with the thermal stimulation of oil sands. This activity appears to be most prevalent near the perimeter of the steam chamber, although some events may originate from within it. These events are likely a result of the cumulative in situ and thermal stresses undergoing an effective stress reduction as the high pressure steam chamber advances into the reservoir. This results in localized shear displacements.

In 1989, four 3-component geophones were installed at a depth of 40m, to monitor the Phase A pattern. An additional geophone was installed in the underground tunnels below the Phase A steam chamber. The geophones were recorded continuously, with significant events stored on tape for subsequent analysis.

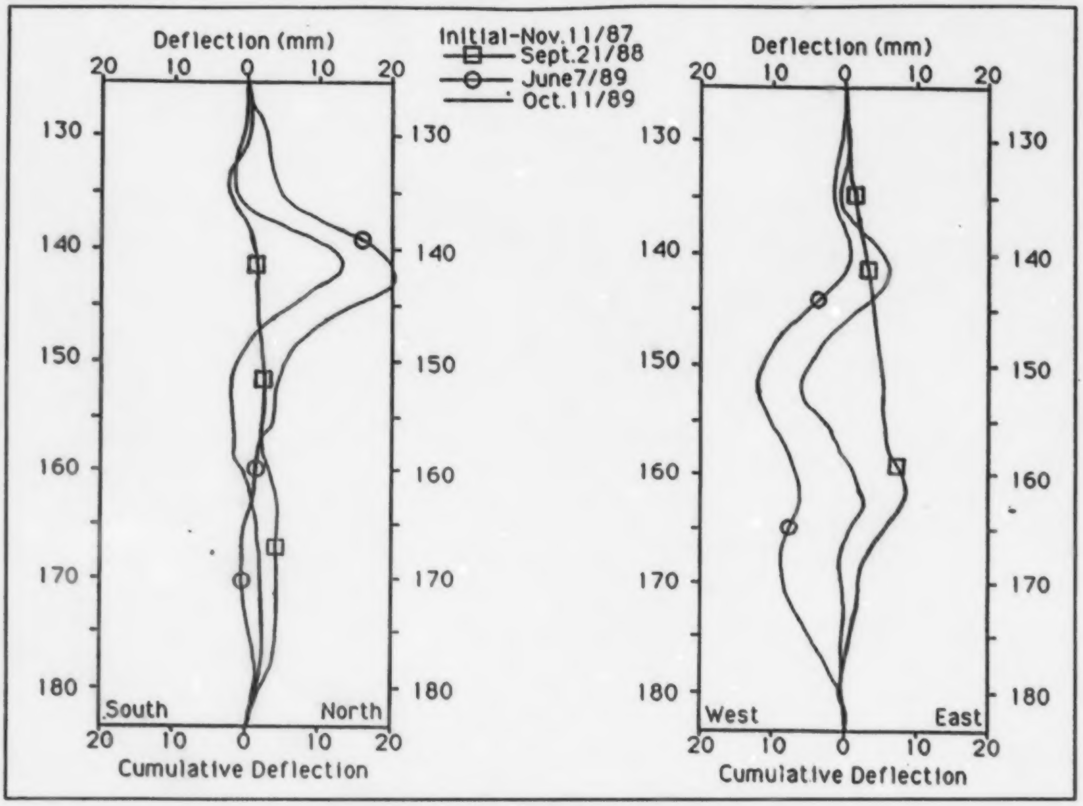

Figure 10. Sample of inclinometer readings.

This method has the potential of allowing continuous monitoring of the steam chamber Progression, using relatively few, remote, instruments. It remains to be seen if the micro-seismic events coincide with the steam front and the geophysical analysis has yet to be refined.

Horizontal Well Instrumentation

Thermocouples were installed in the three horizontal Phase A production wells. Installation of seven point bundles in a sealed 25 mm tube was desired, however, the bundles were not stiff enough to push past 35–40 meters into the upwardly inclined wells. As the tube was sealed, it was not possible to pump in the thermocouple bundle. One multipoint installation and two single point installations were eventually installed by pushing in a support pipe or rod attached to the thermocouples. In the longer Phase B wells, a "pig" will pull in the thermocouples and bubble tubes on a cable.

PHASE B PILOT

The success of Phase A piloting indicated that a follow-up effort should be initiated. This Phase B pilot will consist of three 600 m well pairs, with a completion intervals of approximately 500m. As with Phase A, an extensive monitoring program is included with Phase B. The Phase B monitoring wells were drilled during March and April, 1990. The thirty monitoring wells, shown in Figure 11, consist of: 12 cased wells for inclinometer and temperature monitoring and for cross hole seismic, 5 inclinometer wells which also monitor temperature, 5 piezometer wells which also monitor temperature, 12 temperature wells, and one extensometer well.

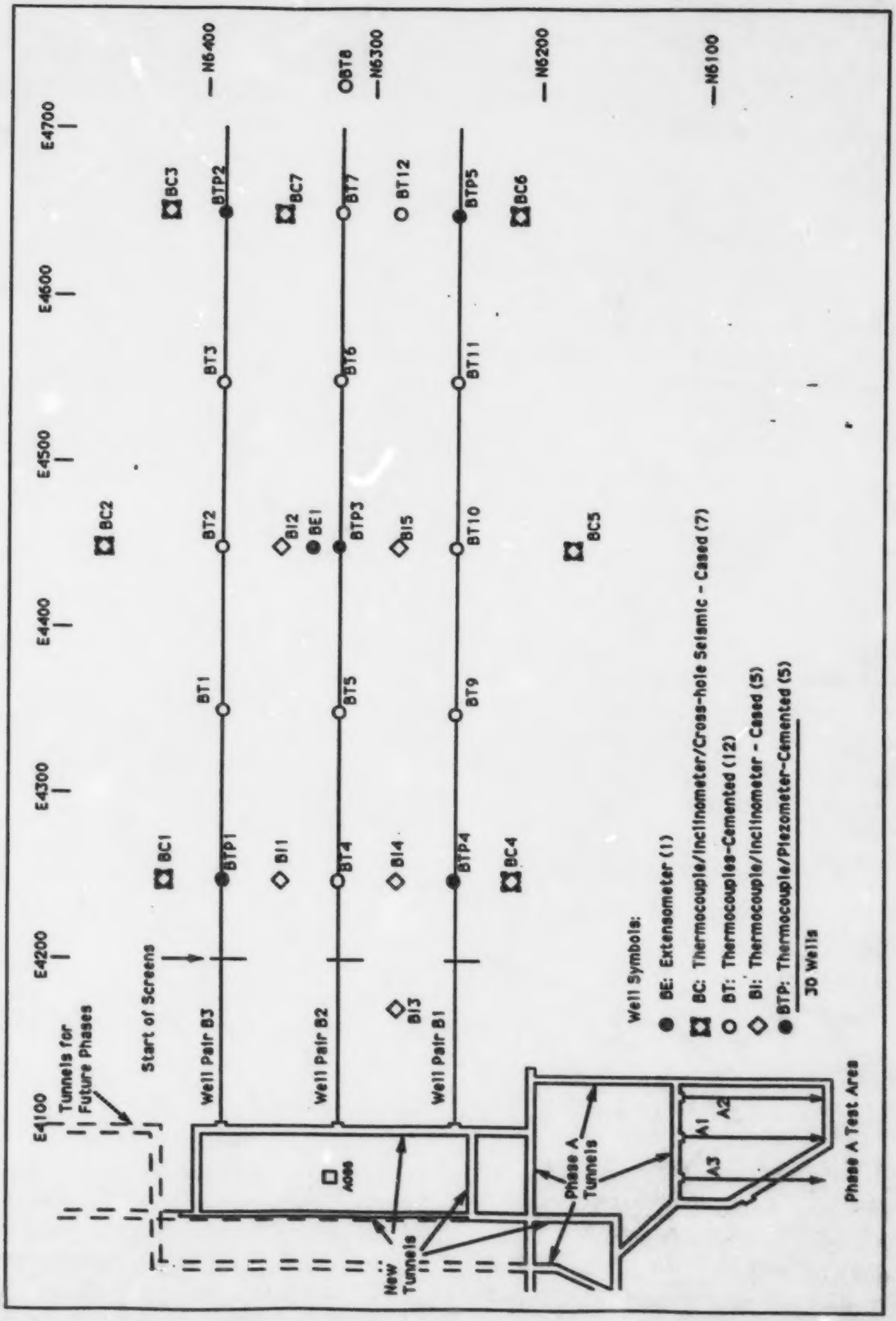
E4100
E4200
E4300
E4400
E4500
E4600
E4700
N6400
N6300
N6200
N6100
Tunnels for Future Phases
Start of Screens
Well Pair B3
Well Pair B2
Well Pair B1
BC1
BC2
BC3
BC4
BC5
BC6
BC7
BTP1
BTP2
BTP3
BTP4
BTP5
BT1
BT2
BT3
BT5
BT6
BT7
BT8
BT9
BT10
BT11
BT12
BI1
BI2
BI3
BI4
BI5
BE1
A086
New Tunnels
Phase A Tunnels
A1
A2
A3
Phase A Test Area
Well Symbols:
● BE: Extensometer (1)
BC: Thermocouple/Inclinometer/Cross-hole Seismic - Cased (7)
○ BT: Thermocouples-Cemented (12)
◇ BI: Thermocouple/Inclinometer - Cased (5)
● BTP: Thermocouple/Piezometer-Cemented (5)
30 Wells

Figure 11. Phase B surface well layout.

PHASE B MONITORING OBJECTIVES

The main objectives of the Phase B monitoring program are to define the shape of the steam chamber and the pressure and temperature distribution within the pattern and along the horizontal wells.

With these objectives in mind the following points are noted:

1. Considerable information on instrumentation performance has been collected from the Phase A and HASDrive pilots. This experience has indicated that temperatures are presently the most reliable evaluation tool for determining steam chamber size and shape. For this reason, temperature information will be collected from all but one of the Phase B monitoring wells;
2. Phase A test results and numerical simulation indicate that uniform steam distribution along the horizontal wells is critical; and
3. Because of the comprehensive geotechnical data collected from Phase A, the same detail of data acquisition will not be required from Phase B.

The specific objectives Or the Phase B monitoring program are to:

1. Monitor the temperature and pore pressure changes and the compressive and shear deformations and surrounding the steam chamber.
2. Monitor the integrity of the shafts and tunnels.
3. Monitor the integrity of the horizontal process well completions.
4. Investigate and report on the performance of the monitoring instrumentation and continue to develop improved cost effective instrumentation designs.
5. Monitor the wellbore hydraulics and pressure distribution within the horizontal wells to optimize future development programs.
6. Investigate the viability of seismic techniques for defining the size and shape of steam zones.
7. Determine what instrumentation is best suited to monitor the geomechanical responses of the formation.
8. Determine the cost efficiency of a geotechnical monitoring program to aid in the improvement of future and other bitumen recovery tests.
9. Assemble a data base on formation responses to the in situ recovery processes which could be applied to future UTF expansions and other projects.

PHASE B INSTRUMENTATION

The Phase A tests have provided a substantial volume of information regarding steam chamber growth. One of the more important findings from Phase A is the practicality of increasing well pair spacing from the initial 24 m to 70 m as shown in the well layout on Figure 11. This increase in spacing combined with longer well lengths (500 m completion interval verses 52 m for Phase A) resulted in a Phase B observation well density approximately one-twentieth of that used at Phase A.

Inclinometer Wells

Horizontal deformations will also be measured from five inclinometer/temperature wells within the pattern using the same rate gyro technique as used in Phase A. In Phase A, inclinometer wells proved to be very effective in describing the spread of the steam chamber. Well BI3 will monitor the horizontal reservoir movement at the point where the horizontal wells enter the oil sands from the underlying limestone. Although no indication of differential movement between the oil sands and the limestone were experienced at a similar Phase A well, the larger Phase B pattern may produce different results because of the larger heated pattern.

Extensometer Well

One well will be drilled in Phase B for the installation of vertical strain measuring equipment. AOSTRA's experience with LVDT (Linear Variable Differential Transformer) type devices was satisfactory until steam engulfed the electronics, at which time the devices became erratic and subsequently failed, as discussed earlier. The design of the new extensometer is Proceeding with the intention of locating all electronics outside the potential heated zone.

Passive Seismic

Pending the results from the Phase A tests, further implementation of the passive seismic monitoring may be undertaken in Phase B.

Horizontal Well Instrumentation

In addition to the vertical wells, temperature and pressure data will be collected from inside the horizontal wells. The primary need is to obtain a pressure distribution along the horizontal well.

SUMMARY

Phase A

The Phase A geotechnical monitoring program has proven to be very helpful in interpreting the Performance of the SAGD recovery process being tested al the UTF. Temperatures have proved to be the most useful data collected from the vertical monitoring wells for monitoring the growth of the steam chamber. Accurate temperature profiles have been obtained from both cemented and cased wells. The disadvantage with the cemented wells is the inability to move or remove the thermocouple bundle. The multipoint thermocouple profiler used with the cased wells has proved useful for obtaining temperature profiles with the limited number of endpoints, however, this method is labour intensive. Thermocouples with SS-316 metal sheathing and cemented in situ have an excellent survival history in the Phase A environment.

Both the pneumatic and vibrating wire piezometers provided reliable data until they were enveloped in steam, after which failure followed. Multiple piezometer installations in single wells are possible and practical. The number is limited by the number of wires which can be accommodated in the well. The piezometer actuator, designed for Phase A, has proven to be an effective tool for piezometer installations at the 160m depths of the UTF.

With care, extensometers can be installed at considerable depth. Although the high temperature extensometers appear to remain functional in the steam chamber, their reliability is questionable. Expansion measured with the extensometers is larger than originally expected.

The inclinometer wells used to measure horizontal displacement have been useful in confirming the size and shape of the SAGD steam chamber. Phase A horizontal displacements have not been enough to cause any concern with the safety of the shafts, tunnels, or process well completions.

All of the geotechnical data collected from Phase A has been compiled into a comprehensive data set. This information is unique and provides the field data that will be required to prove the future development of a reservoir geomechanical simulator.

Phase B

Temperature data will be collected from all, but one (the extensometer well), of the Phase B monitoring wells because of the reliability and usefulness of the temperature data collected in Phase A.

Much of the Phase B monitoring wells instrumentation was cemented in situ because of the cost savings and the excellent survival history experience in similar Phase A installations. The use of endless tubing for the cementing of thermocouples into the stand-alone temperature wells proved very effective, both technically and economically.

Piezometers will be used to measure the pressure distribution along the horizontal wells and to monitor fluid leak off in the Wabiskaw sand and Devonian limestone. Fluid leak off has been minimal.

Modified high temperature vibrating wire piezometers will be used in Phase B. The modifications should improve the reliability of the units. Only one pneumatic piezometer installed in Phase B primarily because of the difficulty in obtaining readings with a portable readout unit. The vibrating wire piezometers will be connected into a data acquisition system. Stainless steel bubble tubes, open to the reservoir, will be used periodically to calibrate the vibrating wire piezometer readings.

Thermocouples and bubble tubes will be installed in the Phase B horizontal process wells.

While data close to an observation well, such as temperature and pressure could provide a precise fix on the steam chamber, the number of wells required is not practical for commercial application. Monitoring systems that provide information away from the wells, such as seismic, may provide better coverage, although precision will be poorer.

Remote methods of monitoring the location of the steam chamber, in particular the steam front, will be evaluated. These methods include: cross hole seismic, possibly passive seismic, and possibly surface heave.

ACKNOWLEDGEMENTS

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TEMPERATURE AND PRESSURE MEASUREMENTS IN PERFORATED OBSERVATION WELLS AND ITS DATA EVALUATION

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Xinjiang Petroleum Administration

ABSTRACT

This paper briefly discusses the temperature and pressure measuring equipments used in the thermal recovery observation wells at the Kelamayi oil field. The comparison and analysis of the influence factors for temperature measurement in the perforated and non-perforated observation wells are presented. The conclusion is that it is possible to accurately measure the reservoir temperature in the perforated observation wells (POW). It also points out that is necessary to obtain both temperature and pressure simultaneously in the same observation well. Some applications in this regard are presented.

The appendix of this paper gives the estimation for the influence of the fluid level movement in the POWs on the accuracy of temperature measurements.

INTRODUCTION

In light of field practices and experiences, reservoir temperature measurements during thermal recovery operation are required to be done in the non-perforated observation wells (NPOW), and POWs can only be used for measuring reservoir pressures.

The average depth of the Kelamayi thermal recovery wells is about 200 meters. For observational purposes, the fixed multipoint reservoir temperature profile monitor equipment was installed in some NPOWs. The same equipment and single point pressure measuring device were also put in some POWs. We used a semi-conductor element as a temperature transducer. The temperature signals were transmitted by using a single wire-single signal type. The nitrogen (N_2) pressure actuated process was adopted as a pressure measurement method. Part of this equipment in the wellbore was a small diameter stainless steel tube. Its upper end was connected with a pressure transducer and a high pressure nitrogen source. The temperature signal wire and pressure measurement tube were sealed at the top tree. Both the temperature and pressure signals were sent to the data acquisition computer (Figure 1). After processing, the information could be retrieved and presented in data and curves. The results are illustrated in Figure 2.

The foregoing measuring equipments are mainly used to of steam drive. The basic data of the said equipments are:

Temperature measurement:

Operation temperature: 0–230°C
Accuracy: 0.5% (full range)
Rating pressure: 10 MPa

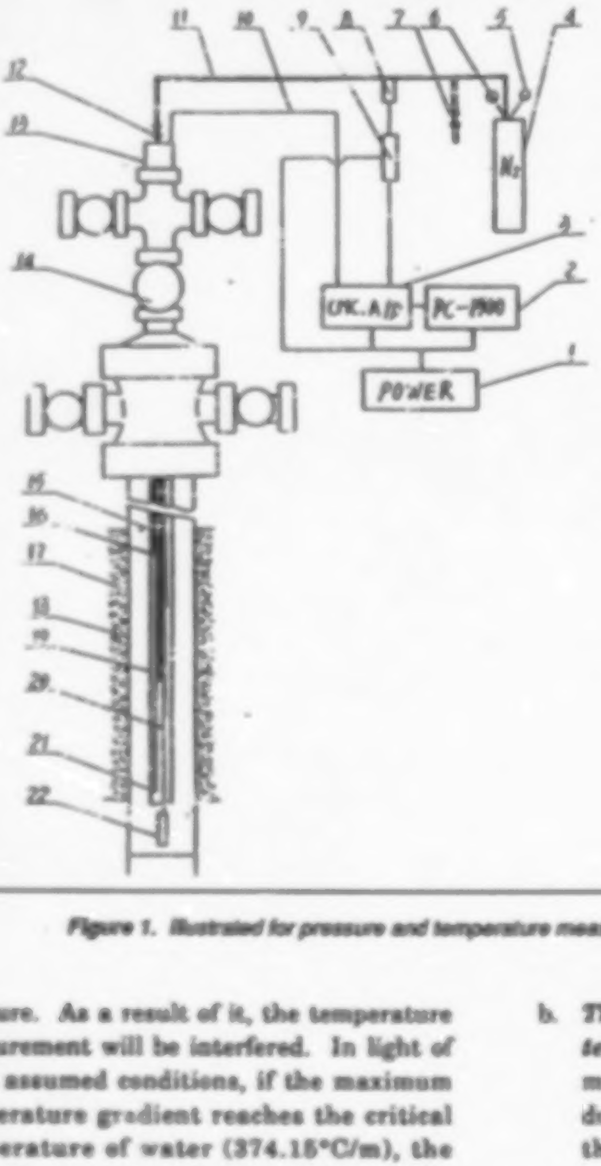
Pressure measurement:

Operation pressure: 7 MPa
Accuracy: 1% (full range)
Rating temperature: 400°C

The conditions and methods for reservoir temperature measurement in POWs

Certain parameters which will affect temperature measurement in POWs (filled with gas, oil and water), and NPOWs (filled with water) are listed in Table 1. We can see from the table, these two kinds of wells have some differences as well as some unanimities.

1. Analysis of some influence factors
   a. ***The effect of wellbore fluid level on the temperature measurements.*** The fluid level in the POWs will vary with the reservoir

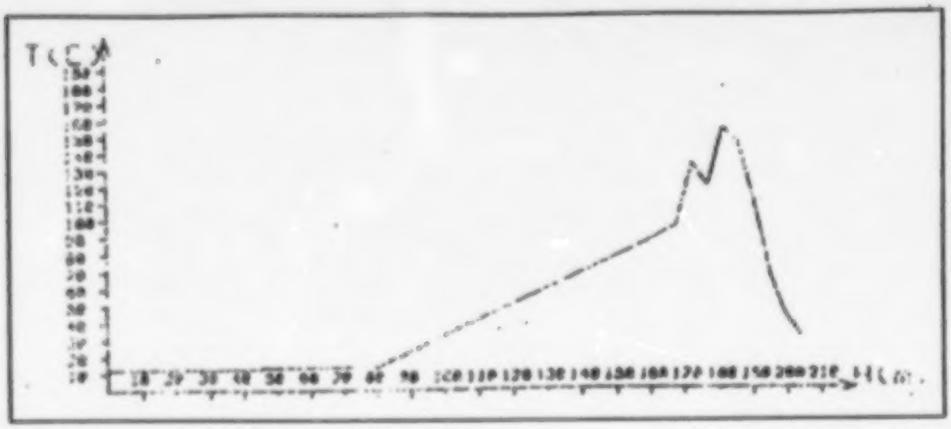


1. power
2. computer
3. A/D
4. N_2 source
5. high pressure gauge
6. low pressure gauge
7. vent valve
8. pressure transducer
9. pressure readout
10. temperature signal wire
11. pressure measurement tube
12. pressure measurement valve
13. connection
14. wellhead
15. tubing
16. temperature transducer
17. payzone
18. casing
19. pressure measurement tube
20. sinker cable
21. temperature transducer
22. sinker bar

Figure 1. Illustrated for pressure and temperature measurement of observation well.

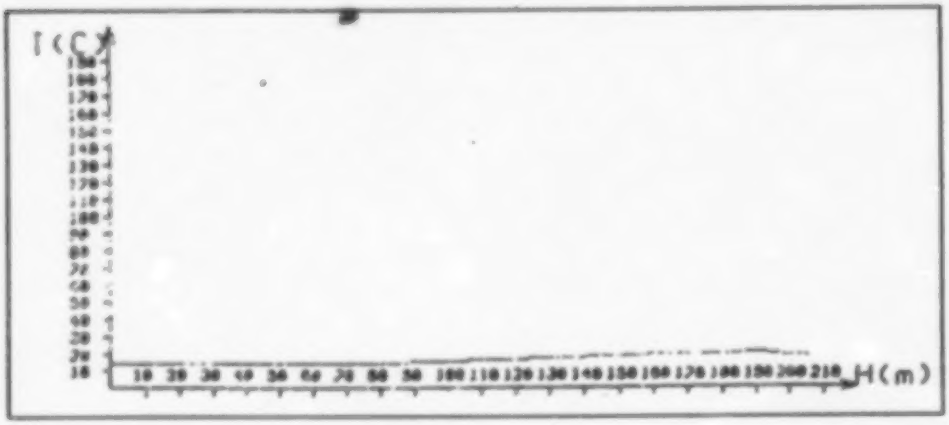
pressure. As a result of it, the temperature measurement will be interfered. In light of some assumed conditions, if the maximum temperature gradient reaches the critical temperature of water (374.15°C/m), the reservoir pressure will change by 0.1 MPa per day. The maximum temperature error of the temperature measurement is about 0.46°C. If we use its saturated temperature, which is in accordance with the reservoir fracture pressure as the maximum temperature gradient of the reservoir, and the other as the above, the maximum error of the temperature measurement is about 0.22°C (see Appendix 1).

b. ***The effect of rising gas in the wellbore on temperature measurements.*** There is not much gas in the upper part of the wellbore due to the oil with low solution GOR. Most of the gas is slowly separated from the oil, because of gradually reducing pressure on the highly viscous oil in the wellbore. For the slowly moving gas with low specific heat and high compressibility, the effect of the rising gas in the wellbore on temperature measurements is negligible. The gas column existing in the POWs is favourable to reduce the temperature error, which is the result from the variation of fluid level in the wellbore by the reservoir pressure changes.



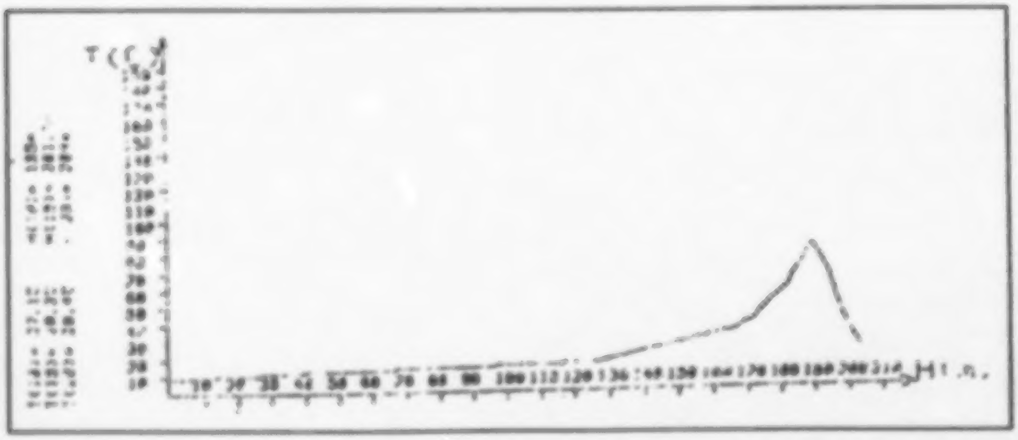
1990
3/7/12: 27.43
= G6:

T(1) = .40 H(1) = 10 m
T(2) = .10 H(2) = m
T(3) = .20 H(3) = 163.5 m
T(4) = .40 H(4) = 168.5 m
T(5) = H(5) = 172.3 m
T(6) = 118.40 H(6) = 181.5 m
T(7) = 152.70 H(7) = 124 m
T(8) = 144.30 H(8) = 186 m
T(9) = 186.50 H(9) = 130.5 m
T(10) = H(10) = m
T(11) = H(11) = 139.5 m
T(12) = H(12) = 284 m
P = H = 195 m



1990
3/7/12: 58.25
= G11:

T(1) = 14.70 H(1) = 10 m
T(2) = 14.70 H(2) = 88 m
T(3) = 20.20 H(3) = 167 m
T(4) = 20.20 H(4) = 173 m
T(5) = 2010 H(5) = 171839 m
T(6) = 19.80 H(6) = 187 m
T(7) = 210 H(7) = 191 m
T(8) = 20.50 H(8) = 195 m
T(9) = 20.10 H(9) = 193 m
T(10) = 18.40 H(10) = 203 m
T(11) = 19.60 H(11) = 207 m
T(12) = 18.30 H(12) = m
P = 1.4 MPa H = 158 m



1990
3/7/13:15.48
= G28:

T(1) = 11.30 H(1) = 8.3 m
T(2) = 13.30 H(2) = 48.3 m
T(3) = 15.20 H(3) = 86.5 m
T(4) = 18.50 H(4) = 128.5 m
T(5) = 33.90 H(5) = 166.5 m
T(6) = 37.70 H(6) = 168 m
T(7) = 38.70 H(7) = 121.5 m
T(8) = 45.20 H(8) = 124 m
T(9) = 43.60 H(9) = 128.5 m
T(10) = 54.40 H(10) = 129 m
T(11) = 58.10 H(11) = 181.5 m
T(12) = 66.80 H(12) = 184 m
T(13) = 73.10 H(13) = 186.5 m
T(14) = 83.60 H(14) = 189 M
T(15) = 770 H(15) = 191.5 m
T(16) = 66.80 H(16) = 194 m
T(17) = 480 H(17) = 196.3 m
T(18) = 37.10 H(18) = 199 m
T(19) = 28.20 H(19) = 201 m
T(20) = 20.40 H(20) = 204 m

Figure 2.

Table 1. Assuming that observation well is completed using steel comparing the temperature measurement the well fluid is naturally formed after completion observation and non-perforated observation well and the as shown the follows:

No.	Effective factor	Perforated	Non-perforated	Explanation
1	The convection in the attached layer of inside wall of casing and nearby area	yes	yes	
2	Heat transmitting and convection of wellbore fluid when temperature is not balanced	yes	yes	
3	Reservoir temperature outside casing and the flowing of the flow with some temperature	yes	yes	This is the purpose of the temperature measurement
4	Depth of the well	yes	yes	The deeper the well is, the better it is
5	Diameter of the casing	yes	yes	
6	Boiling of the wellbore fluid	yes	yes	
7	To manually increase boiling point of the wellbore flow	yes	yes	This is the correct method for the temperature measurement
8	Single wellbore flow	no	yes	The former is the exchanged crude oil
9	Boiling temperature of wellbore fluid	high	low	
10	Communication of the flow inside and outside the casing	yes		
11	The natural changed of pressure in wellbore	yes	no	
12	Manual changes of pressure in the wellbore	no	yes	It will increase the boiling point of the wellbore fluid
13	Flow viscosity in wellbore naturally	high	low	The flow includes crude oil and water
14	Specific heat of flow in wellbore naturally	low	high	
15	Perforated position and controllability for gas liquid interface	yes	/	This is the correct method for the temperature measurement

2. The conditions and methods for correctly measuring reservoir temperature in the observation wells

   a. ***Increasing the boiling point of the reservoir fluid in the pay zone intervals.*** When the high temperature and low pressure exist around the a result, we would not get the real data of the temperature distribution in the pay zone. Therefore, in order to reduce the effect of the wellbore-fluid heat convection, it is necessary to put a certain fluid with a higher boiling point in the pay zone intervals of the observation wells. Such fluid could be a crude oil, which possess higher viscosity in the high temperatures.

   b. ***To lower the position of perforation intervals.*** Normally, the oil-water interface in the wellbore is located at the highest perforated position due to the communication between reservoir and the wellbore. Thus, to lower the perforated position will lower the oil-water interface. This coupled with the wellbore fluid with high boiling point, will assure the temperature measurement for the reservoir with high temperature to be correct.

   c. ***To control the depth of the gas-fluid interface when the well is shut in.*** As mentioned above, the gas column with some pressure existing in the observation well is favourable to reduce the error of the temperature measurements. However when the well is shut in, it is necessary to control the gas-liquid interface, otherwise the wellbore above the highest perforated position will be filled with gas. In this case, the gas is unfavourable for high temperature measurements. The correct position of the gas-fluid interface should be some distance above the top of the reservoir. The required operation of controlling the gas-fluid interface may not be very often. If the well is open, such operation will not be needed.

FIELD EXAMPLE THE EVALUATION AND APPLICATION OF THE TEMPERATURE DATA FROM A POW

Figure 2 is a set of temperature curves taken from the NPOW No. 28 (the wellbore was filled with water, and the measurement interval was 2.5 m), which is located near the cyclic steam injector No. 90911. Figure 3 is a set of temperature curves taken from the POW No. 6 most of the fluid in the wellbore was oil but with some gas and water, the measurement interval was 45 m). The data was recorded during the steam drive period. From the comparison of these two sets of temperature curves, we find some unanimities:

1. Each curve clearly reflects the temperature changes in the reservoir, especially during the high temperature period.
2. The two sets of curves plainly show the temperature changes at the different times.

From these, it is believed that we can measure the reservoir temperatures accurately not only in the NPOWs, but also in the POWs

Figure 2 clearly shows the depth and thickness of the reservoir heated by steam. It also shows the heat breakthrough in he pay zone from [illegible] m to 177 m. The reservoir geological parameters of the said well confirm the reason of heat movement as well.

DISCUSSIONS

The temperature and the pressure measured from the perforated wells can be used separately or be used together. The application of these measurements for !he latter is discussed as follows:

1. To determine the variation of oil and gas phases and the state of steam in the reservoir requires the temperature and pressure to be at the same place at the same time. Thus, the reservoir temperature and the pressure measured from the same observation well are probably necessary. It may not however be adequate to study the relationship among the crude, gas, steam and the light components, which are distilled from the crude at a high temperature.

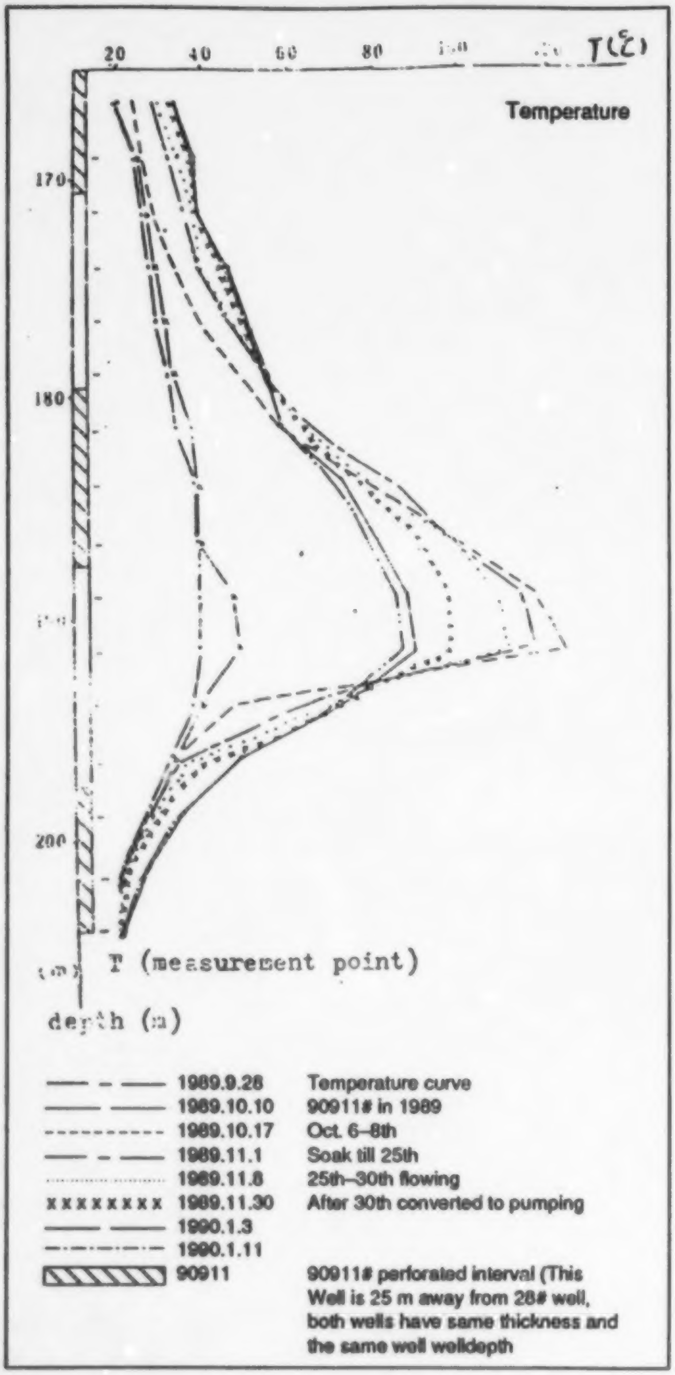


Figure 3. Measured temperature curve in the observation well 28.

2. The measured reservoir temperature and pressure might indicate the possibility of the superheat steam existing at that location. For simplicity, the effect on the water saturation pressure and temperature by hydrocarbon phases is not considered here.

   In the stage of steam drive, steam channeling often caused high temperature to occur along the passage of the steam flow If a very high temperature is measured at a certain point, and the temperature is higher than that at the saturated pressure, the superheat steam may exist at that depth. In general, the only place where superheat steam is present is in the steam channelling passage where the saturated steam exists. Thus, the results of mentioned measurements could decide whether the overriding in the reservoir is wet steam or superheat steam.

3. The thermal parameters of unsaturated water and superheat steam, which are already determined, can be included in the heat loss calculations. However, this should avoid involving the steam quality, since it is difficult to be measured.

CONCLUSIONS

1. When certain conditions are met, the practical temperature data can be measured in the POWs.
2. It is necessary to measure temperature and pressure in the same observation well.
3. Measuring both temperature and pressure in the same observation well can increase its utilization factor. This is important in an economical sense.

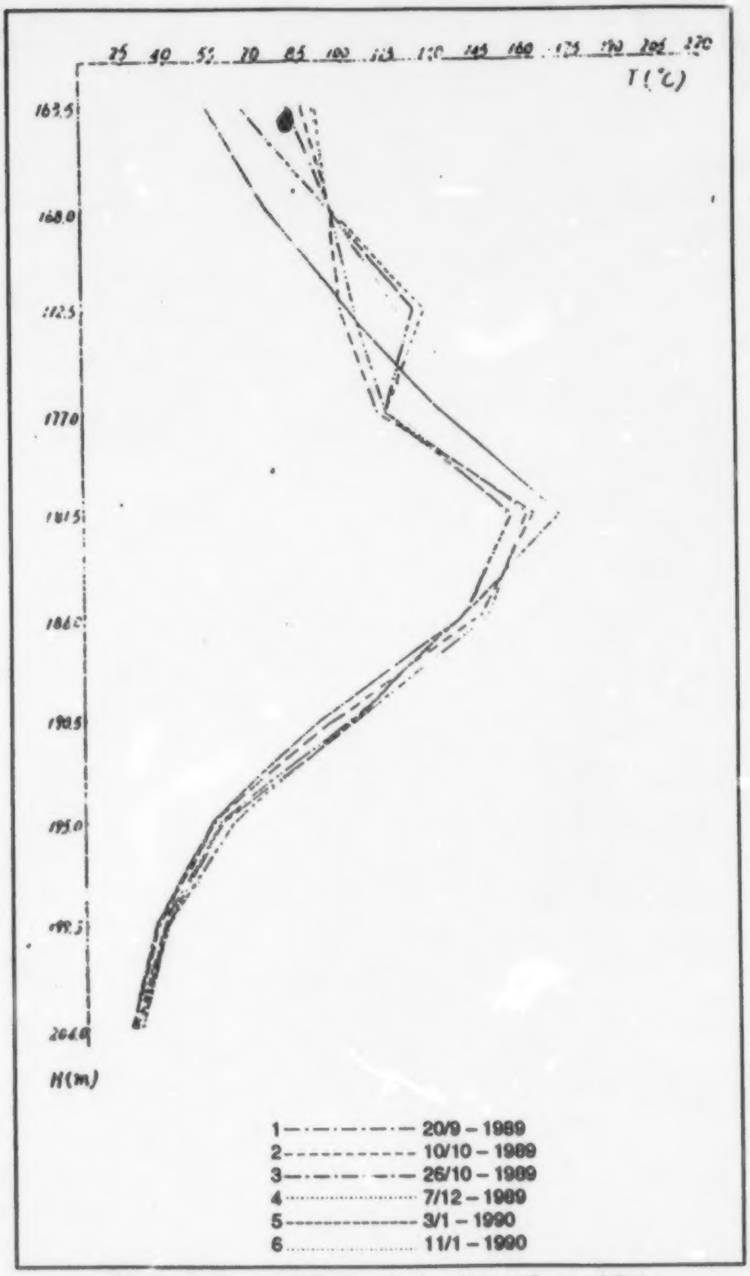


Figure 4. Measured T curve in the observation well G-6.

REFERENCES

1. Zheng, L.Y., Sun, Z.G., Zha, J.X., "Engineering thermodynamics," (in Chinese) National Defense Industry Publisher.
2. Schmidt, E., VDI-Wasserdampftafeln bis 888 C und 1000 at 7 Auflage 1968, Springer, New York, R. Oldenboug Munchen.

APPENDIX 1

The error of temperature measurements due to heat convection inside and outside of the casing.

Assuming the density of the wellbore fluid is ρ

g is the acceleration of gravity

Δp is the reservoir pressure difference

Δd is the fluid level changes in the observation well during time t

If we ignore the influence of gas, we can get the fluid level changes during time t.

(1) $\Delta d = \Delta p/\rho g$

also the rate of change (V):

(2) $V = \Delta d/t$

The maximum temperature gradient in the reservoir is Gr, the time constant of the temperature transducer is c.[9] If we ignore the influence of the radial heat transfer, we can get the maximum error of temperature measurements due the reservoir pressure changes.

(3) $\Delta T_{max} = Gr * V * c$

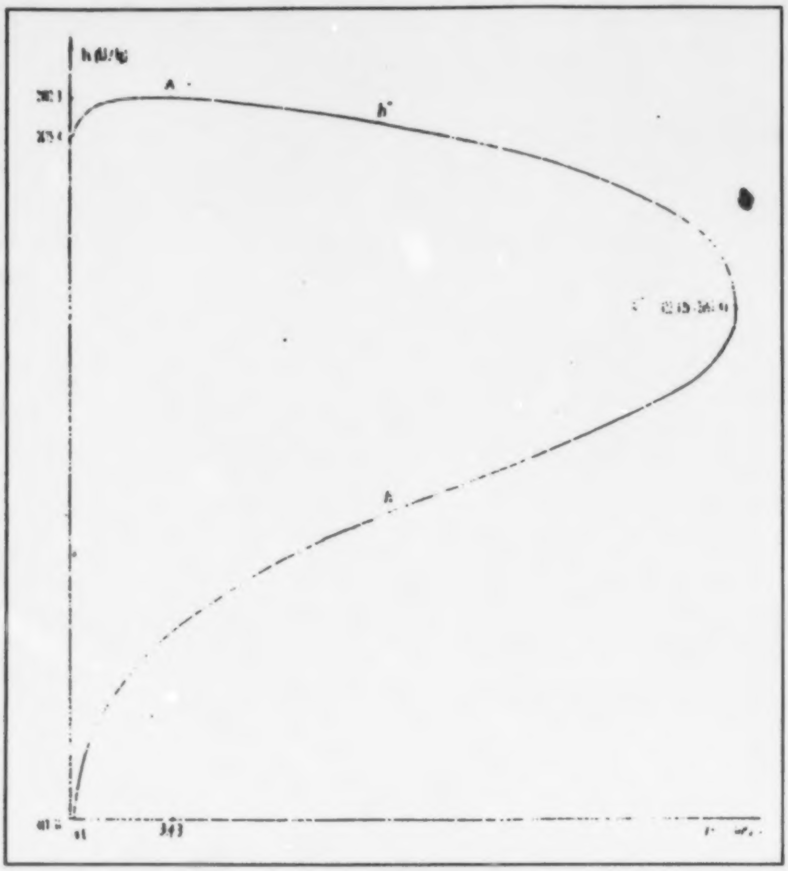


Figure 5. Pressure curve for heat content of the saturated water and saturated steam.

Insert Equations (1) and (2) into (3), and we have

(4) $\Delta T_{max} = Gr * c * p/pgt$

If the reservoir temperature is constant, (4) is the maximum measurement error due the fluid level changes in the POWs.

where ΔT_{max}	temperature measurement error (which is in accordance with c), °C
Gr	the maximum temperature gradient measured in the reservoir, °C/m
c	the time constant of temperature transducer, s
Δp	the reservoir pressure changes in time t, MPa
t	time, which is in accordance with p, s
ρ	the density of the reservoir fluid, kg/m^3
g	acceleration of gravity, 9.80645 m/s^2

Based on the assumed data such as:

Gr = 474.15°C/m (water critical temperature)
c = 10 s, $\Delta p = 0.1$ MPa, t = 86,400 s, $\rho = 950$ kg/m^3

we can simplify (4)

(5) $\Delta T_{max} = 0.46°C$

If we use the saturation temperature, which is in accordance with the reservoir fracture pressure as the maximum temperature gradient, i.e., $Gr = 275.41°C/m$, and by using the same parameters as shown above for equation (4) we can get

(6) $\Delta T_{max} = 0.32°C$

Equations (5) and (6) indicate that such temperature errors are permissible for field application. If we insert the foregoing parameters into (1) and (2), we can get the rate of wellbore fluid changes.

$V = 0.124$ mm/s

This change has no significant influence on the temperature measurement. Although some of the assumed parameters such as Gr may not be adequate, the estimated temperature error, however, is in that range.

SESSION III
Production Technology

ENHANCEMENT OF SOLIDS REMOVAL FROM HORIZONTAL WELLS

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ABSTRACT

Extensive use of horizontal wells for recovering heavy and extra heavy oil from Canadian deposits is improving the economics of recovery processes to competitive levels.

Unconsolidated formations present special challenges to the completion specialists as production rates and life of the well depend on successfully controlling or eliminating sand production. The use of partial sand exclusion in the design of well completions for fine grained reservoirs requires the development of novel, practical methods o remove fines which can accumulate in the long horizontal wells. For most of the horizontal wells, fluid velocity is below critical slurrification values, resulting in sand accumulation, increased pressure drop, and reduced oil production.

This paper discusses the experimental program leading to the development of suitable sand removal strategies using a novel flotation technique. Observations of sand deposition and transportation at low fluid velocities (moving bed) made in a 3" laboratory slurry loop indicated that the formation of transverse and longitudinal sand dunes is a feature of flow and sand movement in horizontal wells. The study described in this paper concluded with a laboratory assessment of a novel method for enhancing solids removal using a cationic non-polluting surfactant and induced air or steam flotation.

INTRODUCTION

Past experience with in situ thermal recovery projects has indicated that in several of these projects, formation sand was produced at such a rate that development of a sand control strategy had to be considered as an essential component of the project.

Two potential sand control strategies were proposed, the first aimed at "total exclusion"[1] and the second, at "partial exclusion".[1] They are now being tested in the Athabasca deposit on horizontal wells.[2,3]

The use of a "partial" sand exclusion[1] strategy in order to minimize the pressure drop and improve productivity while tolerating limited production of fines, is appealing, especially for fine, unconsolidated formations where conventional design of sand control devices ("total exclusion") would lead to excessive pressure drop and plugging situations. However, in order to apply the partial sand exclusion strategy, practical methods for removing the fines from boreholes had to be developed. Figure 1 indicates the potential implications of the total and partial sand exclusion strategies applied to horizontal wells.

The technology for sand removal from long horizontal wells is related to the existing technologies of slurry transportation, placement of propping agents used for hydraulic fracturing, and effective transport of cuttings during drilling operations.

Figure 2 illustrates[4] the flow pattern map of water-solids suspension (60 µm spherical glass beads) as function of the concentration or amount of solids added in a 3/4" (19 mm) horizontal glass line. Transition conditions between "moving bed" and "fully suspended" and the development of special methods to translate this boundary to a lower velocity regime, represent an important focus of this study.

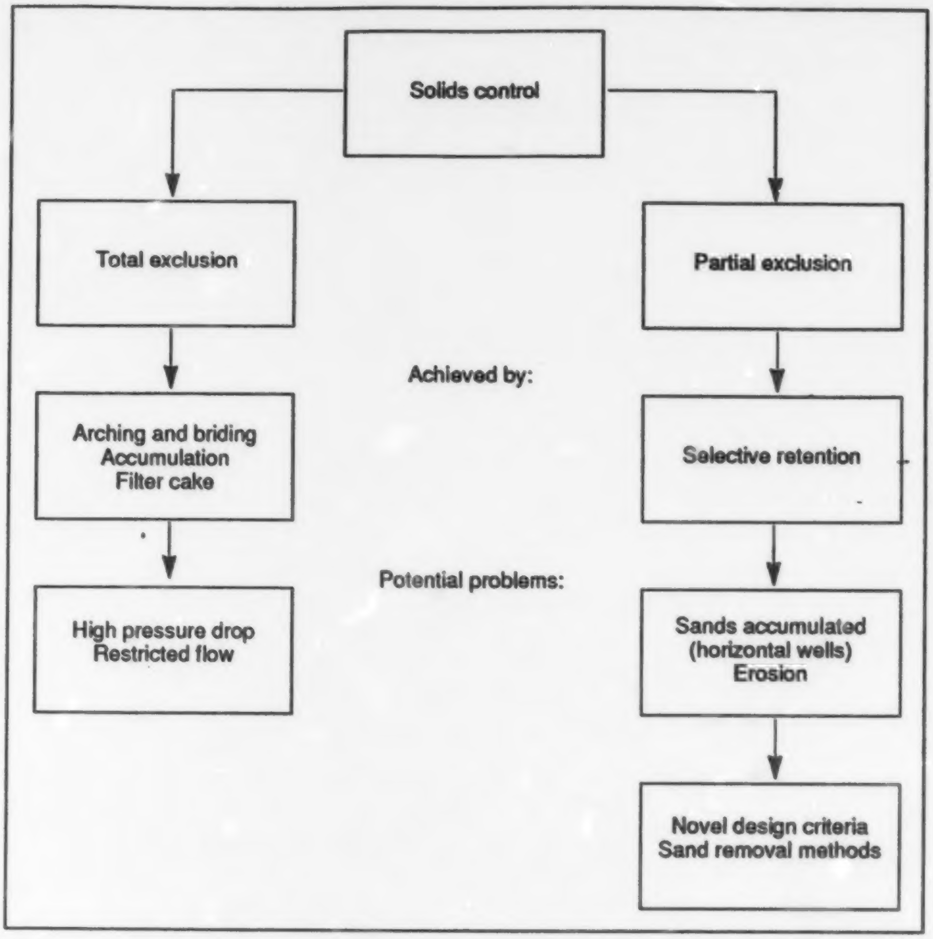

Solids control
Total exclusion
Partial exclusion
Achieved by:
Arching and briding
Accumulation
Filter cake
Selective retention
Potential problems:
High pressure drop
Restricted flow
Sands accumulated
(horizontal wells)
Erosion
Novel design criteria
Sand removal methods

Figure 1. Total and partial sand exclusion and their practical implications to sand control strategy.

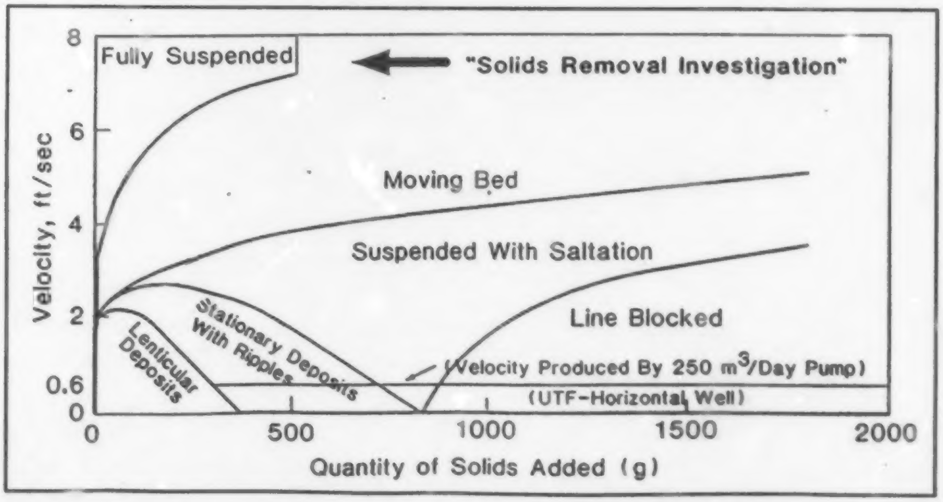


Figure 2. Patterns of sand deposited in a horizontal pipe from a variable concentration of slurry.[4]

The removal of deposited sand using a mechanical devices, or combinations of local agitation and high velocity[6] suction is complicated by the presence of an annular configuration (used for the UTF), the length of horizontal well, and high-pressure, high-temperature regimes used in thermal recovery projects. Achieving a critical velocity of 1.2 m/s in order to clean the 6" (15 cm) UTF well, would be impractical. This paper presents a novel sand removal technique for horizontal wells and a laboratory assessment of its effectiveness.

BACKGROUND

Major Mechanisms

The process of sand removal occurs between two limiting physical conditions:[7]

- all sand is suspended in the carrying fluid (slurry),
- all sand is immobile and deposited on the bottom of the pipe (stationary bed).

The complete distribution of the sand-fluid interface (dune-like rippled surface) associated with the development of turbulent flow patterns, further complicates the understanding of the sand deposition removal phenomena. In spite of years of research into the transport of sand by running water, the physics is still not clearly understood.

Terminal Settling Velocity

In order to determine the conditions required to maintain a solid particle suspended in a fluid, the equilibrium of forces acting on a free-falling particle should be first analyzed. In a laminar upward flow, a particle can be suspended indefinitely if the upward fluid velocity equals the "terminal" velocity (u_t). For simple situations illustrated by viscous flow around a spherical particle, the terminal settling velocity u_t is given by:

$$u_t = f\left[d,\ \mu_f,\ \rho_f,\ (\rho_s - \rho_f)\right] \tag{1}$$

where d is the particle diameter;

μ_f the fluid viscosity; and

ρ_s, ρ_f the densities of the particle and the fluid respectively.

If the upward velocity field is uniform and has a value greater than the terminal settling velocity, solids will be maintained in suspension. However, the simple calculation of the terminal velocity, which equates gravity to drag forces, is usually altered by conditions such as : particle concentration, non-spherical or deformable particle shape, non-uniform size, wall effects (boundaries) and non-uniform velocity distribution, nonsteady flow (acceleration), non-Newtonian fluid behavior associated with the presence of fines, and the presence of mechanisms other than gravitational and drag forces responsible for flocculation, Brownian movement ($d < 2\ \mu m$), and turbulent flow.

Maintaining a particulate, silica sand, in suspension in a long horizontal pipe may be a difficult task unless additional suspension mechanisms are employed. For high-density and relatively large particles ($d \gg 2\ \mu m$) in a laminar flow regime, even for extremely low settling velocities, the particle will eventually deposit on the bottom of the pipe.

To avoid or delay particle deposition, two strategies are currently employed:

- create a highly turbulent regime,
- use a highly viscous or a visco-plastic suspension.

Critical Velocity

A simplified concept for analyzing the transition from moving bed to fully suspended slurry flow is the "critical velocity" defined as the minimum velocity value required for avoiding deposition during a steady-state, slurry pipeline operation.[8] Critical velocity is useful for defining limiting flow conditions for solids removal from horizontal wells. Newitt et al.[4] proposed a relationship derived from his own work and that of Durand,[9] suggesting a critical velocity V_c below which a stationary bed occurs.

$$V_c = F_L \sqrt{2gD\,(S-1)} \tag{2}$$

where F_L is a function of the particle diameter;

g is acceleration due to gravity;

D is the diameter of the pipe; and

S is the ratio of the density of the solids to that of the liquid.

Recently (1980), Oroskar and Turian[8] devised a theoretical expression for the minimum transport velocity based on a dynamic relationship between the turbulent flow and gravity forces which tended to deposit the solids. Kim[9] revisited the existing models and experimental data, and suggested an improved model for calculation of critical velocity. In addition to previously suggested key parameters, Kim introduced the terminal settling velocity as another key parameter for the calculation of critical velocity.

A computer model developed at ARC ("SETL"), was used to perform a sensitivity study of critical velocity as function of the density and viscosity of the carrier. The model also permits a quick comparison between critical deposition velocity, the flow condition of a slurry in a horizontal well, and the terminal settling velocity used for assessing slurry transport velocity in a vertical well. Results are summarized in Figures 3 and 4 illustrating the effect of density and viscosity of the fluid on settling velocity (vertical wells) and on critical velocity (horizontal wells). A strong dependence of terminal settling velocity on viscosity indicates that a rapid increase of fluid carrying capacity can be achieved through a limited increase in fluid viscosity. On the contrary, for a horizontal well, only a slight decrease of the minimum transport (critical) velocity results from a sizable viscosity increase (Figure 4b).

EXPERIMENTAL APPROACH

In order to investigate practical methods to enhance the removal of solids from a horizontal wellbore at fluid velocities lower than the calculated critical slurrification velocity, it was necessary to construct a test loop in which the process could be

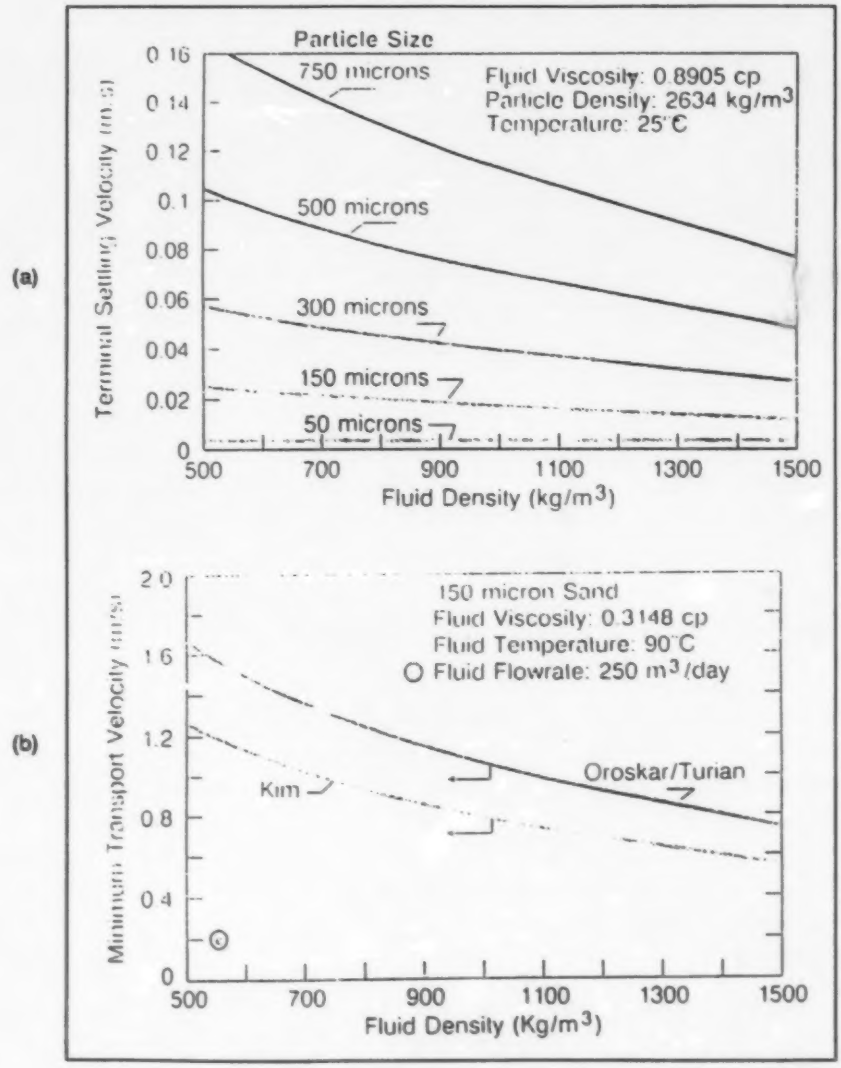


Figure 3. The effect of fluid density on solids deposition in (a) upward flowing suspensions and (b) horizontal wells.

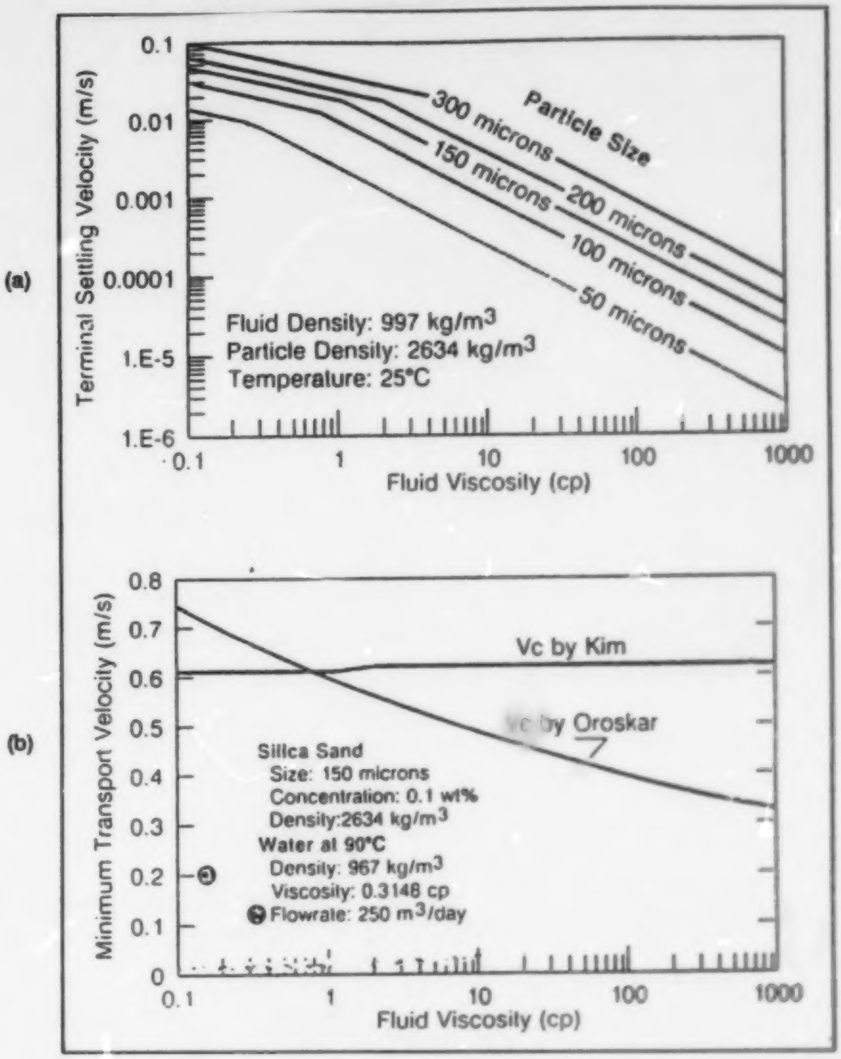


Figure 4. The effect of fluid viscosity on solids deposition (a) upward flowing suspensions (b) horizontal wells.

observed and quantified. Figures 5a, b present schematically the loop designed for this purpose. Three major parts of this loop are:

- observation, (glass section),
- piping (feeding and discharging) system,
- pumping system.

To adequately design the slurry loop the following criteria were used:

- sand or plastic grit (size 50–350 µm) at concentrations of 0–10% to be carried in an aqueous slurry through the piping to the observation section of the loop;
- deposition or retention should be minimal in the piping system while the velocity in the observation section of the loop can be varied over a large range;
- the pumping system should allow the velocity in the observation section to be varied in such a way that:
  - an effective deposition of sand is possible through a sudden or gradual pump velocity decrease,
  - the removal of sand deposited in the observation section can be achieved and observed while the pump velocity is gradually increased.

Two parallel pumps (of variable speed) and two parallel horizontal pipes were employed in the feed lines. The 3 m long observation section uses a 3" (76 mm) diameter glass tube which extends for 6 m and is situated in a horizontal position at approximately 6 m above the pumps. The inlet section, upstream from the observation section, consists of a 2-m section of 3" (76 mm) glass tube used to stabilise the turbulent flow after the expansion from the vertical branch of the loop (25 or 38 mm). The exit from the observation section is connected to 1 m of 76-mm glass tubing extended to the 38-mm PVC piping to the slurry tank.

The intake of variable-flow Mueller and Kharva slurry pumps is connected to a 450-L tank provided with a pneumatic stirrer to maintain the solids in suspension. The pump discharge can be alternately connected to a 25-mm or 38-mm PVC pipe. A "micro-motion" mass flow meter can be connected to each line as desired. Should it be necessary to remove and weight the solids from the observation section, flow can be diverted through a filtration unit before being returned to the tank. In addition to the mass flow meter, a pilot tube is mounted just upstream of the glass observation section so that fluid velocity can be directly measured. The pressure drop across the observation section is measured using a Rosemount pressure transmitter. Pressure drop and flow data are logged using a small process control computer.

Flow control is achieved by having separate SCR motor speed controls on both the Mueller and Ebarra pumps. Visual observations of solids transport taking place in the observation section, is monitored and recorded using a Panasonic digital video camera connected to a VHS video cassette recorder.

Figure 6 illustrates the head loss versus flow rate for the Mueller and Ebarra slurry pumps and also indicates the loop flow characteristics for 18 m of pipe 19, 25, 38, and 76 mm in diameter.

Each experiment involved two distinct stages: sand deposition and sand removal. To study the deposition of solids in horizontal piping, the solids were added to the slurry tank while

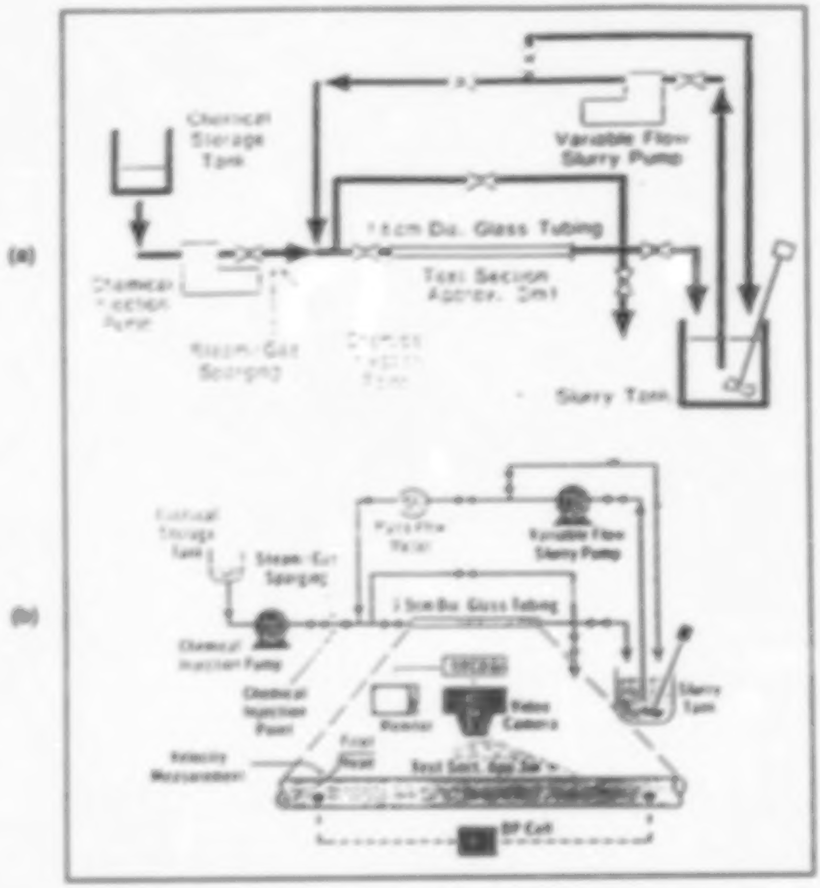

(a)
Chemical Storage Tank
Variable Flow Slurry Pump
1.5 cm Dia. Glass Tubing
Test Section Approx. 3 m
Chemical Injection Pump
Steam/Gas Sparging
Slurry Tank
(b)
Variable Flow Slurry Pump
Steam/Gas Sparging
Chemical Injection Pump
Video Camera
Velocity Measurement
DP Cell
Slurry Tank

Figure 5. Solids entrainment test loop (a) schematic; (b) instrumentation.

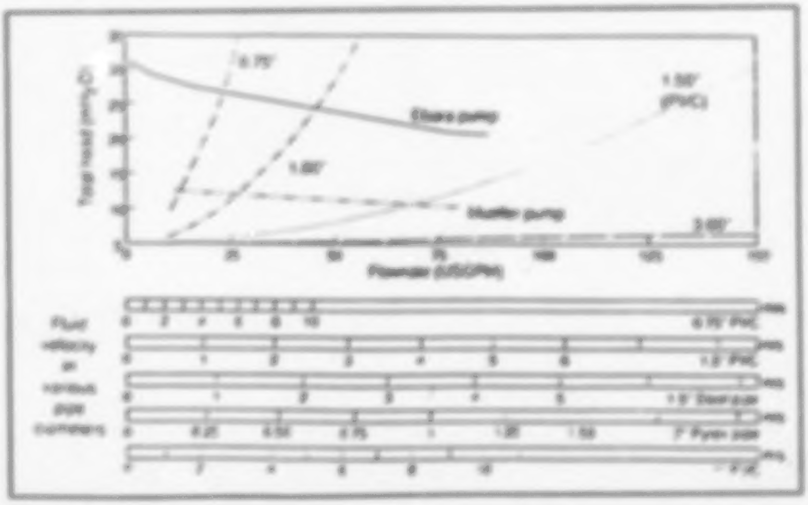


Figure 6. Pump performance data (head versus flowrate).

the pump was set at maximum flow rate. The fluid velocity was then lowered slowly until sand was deposited in the observation section. Flow parameters and sand movement were recorded using the measurement system and the video camera. To observe the sand-removal process, solids at 0.1 or 1.5% by weight were added to the slurry tank in the same manner and after a suitable period of time, the pump was stopped, causing the solids to be deposited in a continuous bed on the bottom of the glass observation section. The pump was then restarted and the fluid velocity slowly increased while the solids movement was recorded

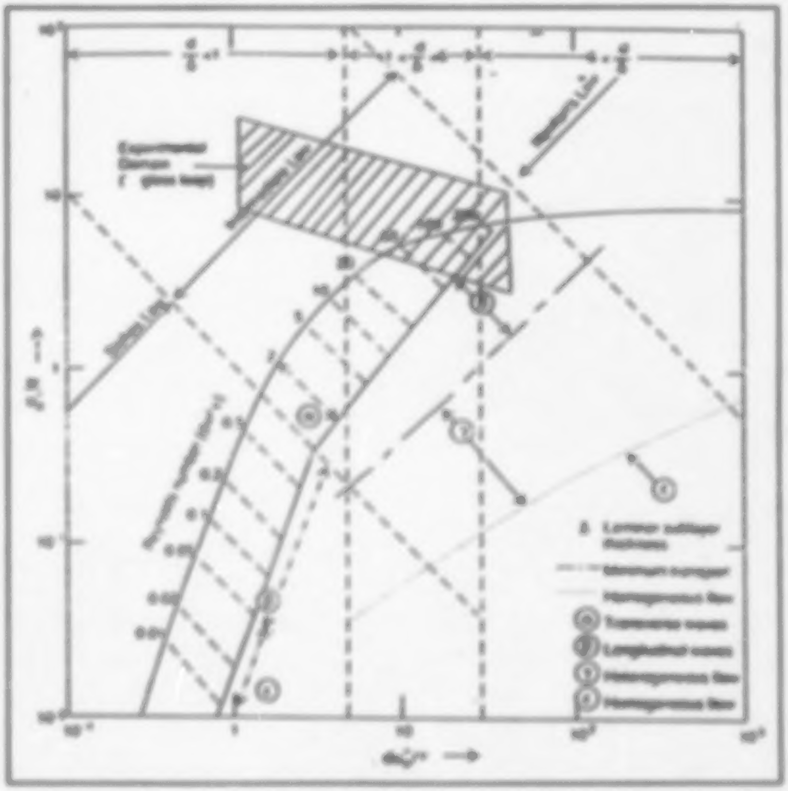
RESULTS

Experimental Data and Model Predictions

A first series of experiments was conducted to observe and quantify the transport behavior of a layer of deposited sand under the influence of gradually increasing water velocity. Silica (density 2634 kg/m^3, size 82427 µm) and plastic particles (density 1530 kg/m^3, size 153–605 µm) were employed. To identify potential conditions of sand movement in the 76-mm glass observation section, Thomas' generalized phase diagram[11,12] for suspension transport was used. In order to use Thomas' predictions, a plot of u_t/u_c^* versus du_c^*/v was generated [where u_t is the terminal settling velocity and u_c^* is the friction velocity for a case of infinite dilution, and v is the kinematic viscosity]. Friction velocity is defined as $u^* = (\tau_w/\gamma)^{1/2}$ where d is the particle diameter. Figure 7 illustrates the flow pattern boundaries as well as the investigated area.

For the equipment designed and achievable flow regime, (velocity up to 1.2 m/s) in the 76-mm tube, two types of dunes are observed: transverse dunes (α dunes) and longitudinal dunes (β dunes). The transverse dunes have the appearance of discrete clumps or islands of sedimented particles and creep along the bottom of the pipe in the direction of flow. Longitudinal dunes are less stable and have a height of approximately 0.1 to 0.4 of the pipe diameter.

Depending on the particle size and density,



for $\dfrac{\rho_s - \rho_l}{\rho_l} = 1.63$

u_c^* friction velocity at minimum transport conditions:

$$u_c^* = \sqrt{\frac{\tau}{\rho}} = \sqrt{\frac{D\Delta p}{4\rho L}}$$

Figure 7. Domain of investigations according to Thomas' generalized diagram for suspension transport.[11]

heterogeneous flow, and even a homogeneous slurry, can be achieved. Table 1 indicates the calculated flow characteristics for bulk velocity in the range of 0.1 to 1.1 m/s. The thickness of the laminar sub-layer as well as the friction velocity, are indicated for further reference and comparison to particle/dune size.

The area of experimental points in the Thomas' flow pattern diagram (see Figure 7) suggests dividing the study into two groups of experiments for transverse and longitudinal dunes.

Particle Size

Figure 8 compares the critical velocity, a function of particle size as predicted by the Kim model, with experimental data. The velocity range observed for transition from mobile transverse dunes to heterogeneous slurry flow is identified for each particle diameter and compared to calculated critical velocity.

Visual observations made during the formation of dunes under the influence of a gradually decreasing and increasing bulk fluid velocity indicate that the transverse dunes do not coalesce or grow into larger dunes but maintain their identities and travel together at approximately the same speed.

Table 1. The hydrodynamic characteristics of water flow in a 3" glass tube.

Bulk velocity (m/s)	Friction velocity (m/s)	Friction factor	Laminar sub-layer (microns)
0.1	6.69×10^{-3}	8.96×10^{-3}	1512
0.2	12.56×10^{-3}	7.89×10^{-3}	805
0.3	18.30×10^{-3}	7.46×10^{-3}	553
0.4	24.00×10^{-3}	7.20×10^{-3}	421
0.5	29.67×10^{-3}	7.04×10^{-3}	341
0.6	35.33×10^{-3}	6.93×10^{-3}	286
0.7	40.97×10^{-3}	6.85×10^{-3}	247
0.8	46.61×10^{-3}	6.79×10^{-3}	217
0.9	52.24×10^{-3}	6.74×10^{-3}	194
1.0	57.87×10^{-3}	6.70×10^{-3}	175
1.1	63.50×10^{-3}	6.67×10^{-3}	159

Note: For the relative roughness of a smooth tube (2.6×10^{-5})
Data obtained with the model "Thomas" ARC

Figure 9 illustrates the observation section of the slurry loop as well as a typical sequence of transverse waves.

Particle Density

To observe the effect of particle density on minimum transport velocity, a few experiments were performed using plastic grit (density 1530 kg/m³) instead of silica sand. It was observed (see Figure 10) in general, that for lower density material, the transition from stationary bed to heterogeneous slurry flow exhibited a narrower velocity range than for the more dense silica. A scale modification of the Y-ordinate of Thomas' phase diagrám (see Figure 10) with the density factor:

$$(3) \quad \left[(\rho_s - \rho)/(\rho_{sp} - \rho)\right]^{0.33} = 1.45$$

explains the reduction of the velocity interval (linear scale) when plastic grit (density ρ_{sp}) is used instead of silica sand (ρ_s).

Deposition and Removal of Large Dunes

In order to assess new methods for removing sand accumulated in horizontal wells, a baseline removal regime for transverse and for longitudinal dunes had to be first determined experimentally. The dynamics of transverse dunes deposited and formed from a thin layer of sand, involved the assessment of threshold fluid and dune velocities. Assessing the dynamics of transverse wave-type dunes was a straightforward task, as they have a reproducible wave length, height, and velocity.[18]

However, the study of the deposition and removal of longitudinal dunes is complicated by their diversity in the shape, length, and depth. A systematic study was therefore initiated in order to develop a technique for the deposition of a "laboratory reproducible longitudinal dune."

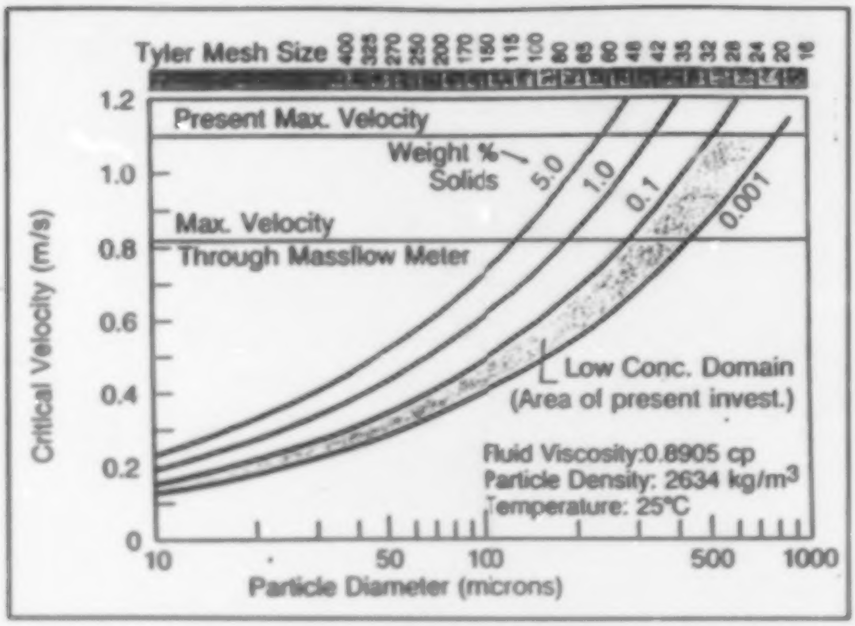


Figure 8. Critical transport velocity as functon of particle diameter and slurry concentration (Model "SETL", Appendix 1).

Two relatively narrow ranges of sand size (–70+140 mesh and –40+70 mesh) were selected for producing base line conditions.

The following procedure was selectd for the deposition of a large dune in the entrance region of the observation section:

1. Mix 4500 g sand (silica –40+70) with 210 L water in the mixing tank, (approximately 300 L in the system & tank) to achieve a concentraion of 1.5 wt%.
2. Recirculate the slurry for 20 min at a rate corresponding to 0.2 m/s in the 76-mm gass loop.
3. Isolate the glass observation section and, using a bypass section, recover the sand deposited elsewhere; record the sand balance.
4. For 10 min, monitor the dune transport characteristics (leading/trailing edge displacement) at a velocity of 0.3 m/s videotaping the sand movement and collecting all sand separated in a hydrocyclone.
5. Increase fluid velocity in increments of 0.1 m/s every 10 min and collect sand produced in each step until all sand was removed from the observation section.
6. Perform a final washout at maximum pump speed to recover and collect all sand from the loop.

Table 2 summarizes the sand balance data for 14 consecutive experiments where the above procedure was utilized. A good reproducibility is observed for the initially deposited sand; the final balance (loss) was also considered satisfactory (1.3 to 6.5% for –40+70/–70+140 and 9 to 11% for oil-stripped Athabasca sand (complete size range).

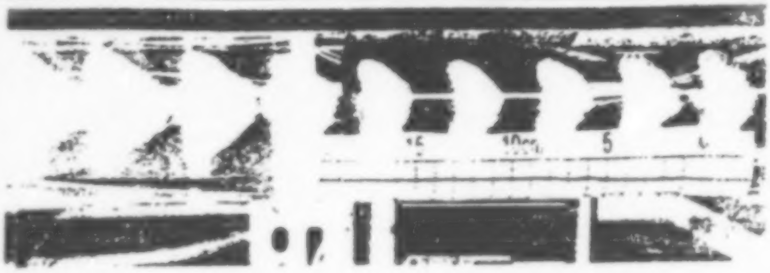
ENHANCEMENT OF SAND REMOVAL

The use of flotation was proposed as preferred strategy for the enhancement of sand removal.

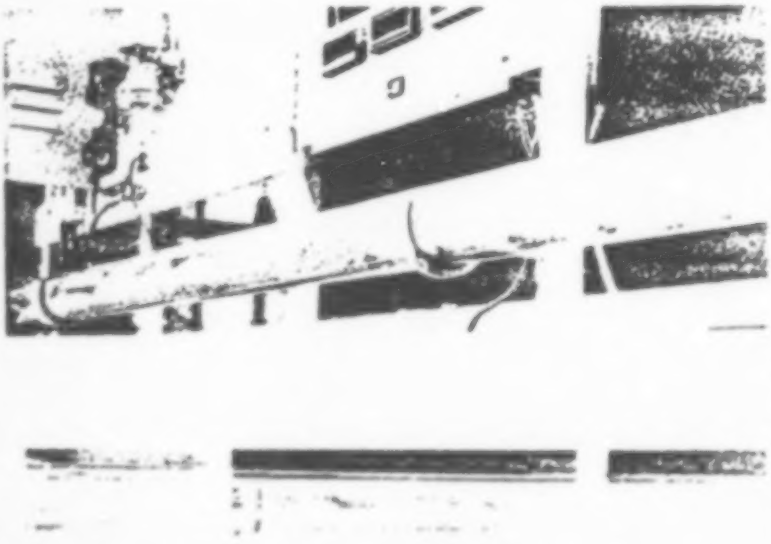
This study involved laboratory investigations assessing the preferred dressing agent and its stability under typical field conditions; testing the technique in the 76 mm glass tube for sand removal and in a specially designed loop to assess the possibility of using in situ sudden-vaporization (flashing); and finally, comparing each technique to baseline removal conditions.

Equipment and Experimental Procedures

A preliminary laboratory bench-scale experiment was performed using a standard flotation cell to assess optimum flotation conditions for typical Athabasca oil sands. The cell consists of a variable-speed rotor mounted on the end of a shaft which can be raised or lowered into a stainless steel or plastic container holding the sand and water slurry. Silica and water are both polar compounds and therefore the silica tends to be hydrophilic. Adding relatively



Transverse sand dunes deposited in the 75 mm glass loop from diluted sand slurry.



Longitudinal sand dunes deposited in the 75 mm glass loop from concentrated sand slurry.

Figure 9. Typical transverse (a) and longitudinal (b) dunes – baseline study.

small amounts of the "collectors" causes the particles to attach themselves to the air bubbles.

After identifying the family of chemicals best suited to the flotation of silica, tests were carried out on four types of long-chain diamines. A standard test was devised using the laboratory-scale flotation cell in which a 150 g charge of Ottawa sand sized at –80+100 mesh (average grain size 150 mm) was added to approximately 4 L of deionized water having a pH of 8.2. The slurry was agitated with the rotor speed set at 1000 rpm to ensure that the sand particles were continuously suspended. The collector chemical was then added in amounts ranging between 25 and 300 g/tonne of solids present. Before the air was introduced, the slurry was "conditioned" for 5 min to allow for the interaction of the solids and the collector. Each chemical was tested in turn using the same procedure.

Test Results (Standard Flotation Cell)

a. Selection of Chemicals. Two chemicals were chosen as having a satisfactory response in terms of percent solids recovered. These two chemicals were then tested against a variation in pH. Sulfuric acid or sodium hydroxide was added to produce a range of pH between 6 and 11 (Figure 11).

b. Optimal pH regime. The two most promising collectors were then tried in a variable pH environment with the results indicating that the optimum pH between 7.5 and 8.5 produced recoveries of between 80 and 95% (Figure 12). During this series of experiments, the collector was added in the same amount (100 g/tonne solids) and the temperature was maintained at 21°C.

c. Influence of grain size. Following these tests, the efficiency of removing solids was investigated as a function of grain size using a fixed amount of additive (100 g/tonne). The results, which are graphically illustrated in Figure 13, indicated that the maximum recovery (>80% recovery) was achieved for solids in the range of 75–200 mm

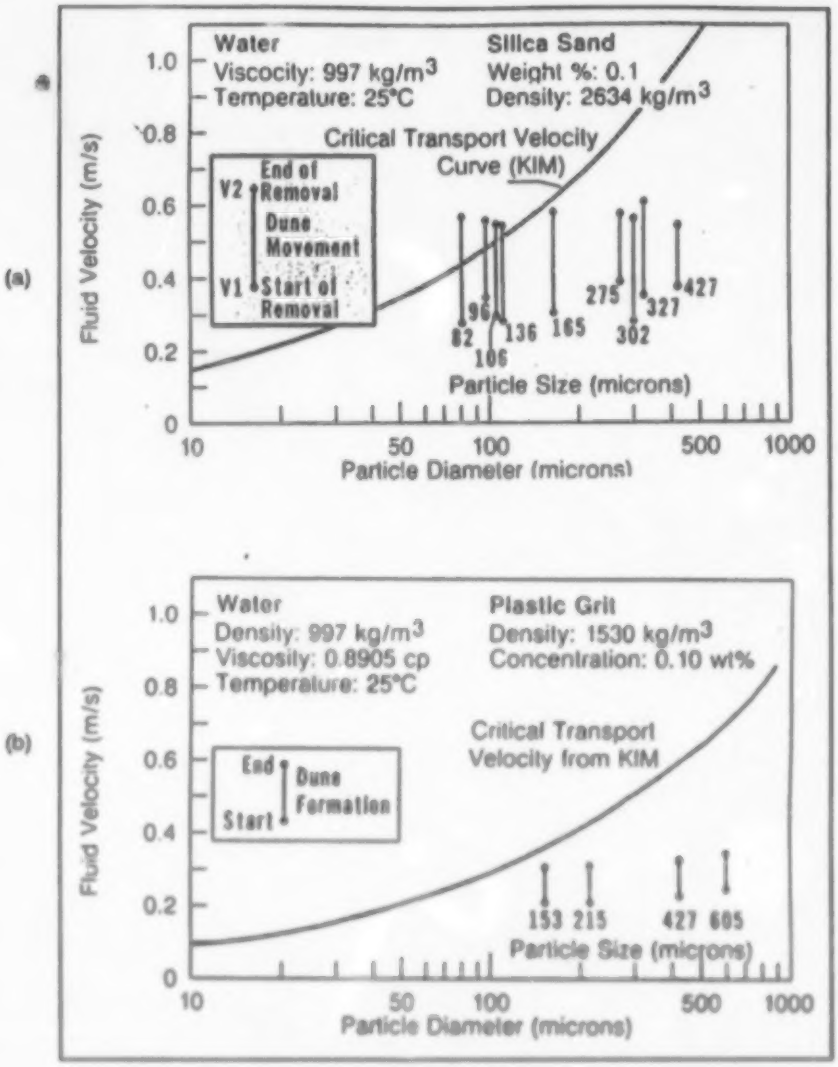


Figure 10. Comparison of experimentally determined transition from stationary bed to heterogeneous slurry flow and calculated critical velocity for various sizes of silica sand (a) and plastic grit (b).

(200-75 mesh). The excessive adsorption of collector for silica sized smaller than 100 mm (large interfacial area) reduced the superficial concentration of the collector to below the level of concentration required for proper gas bubble attachment. Increasing the size of the particle above 180 mm reduces flotability due to the associated increase in mass. This explains, in simple terms, the occurrence of an optimal size range found in this experimental work.

d. **Influence of bitumen and temperature.** To simulate more closely the conditions that would perhaps be present in a horizontal wellbore which has been producing heavy oil or bitumen for an extended period, two 175-g samples of surface-mined oil sand were tested using the selected collector at a temperature of 85°C. Figure 14 illustrates the results from the test in which "high-grade" oil sand was used. With the addition of approximately 100 g/tonne of solids, the preferred additive collector recovered 76% of the solids originally present. Figure 15 illustrates the results obtained with a "low-grade" oil sand sample in which 55% of the solids were recovered. The reduction in recovery can be attributed to the presence of larger amounts of fines which tend to consume some of the collector, reducing its overall effectiveness.

For the flotation process to be effective, the following conditions should be met:

- dispersion of the solids
- introduction of the reagent
- contacting of the air, solids, and reagent.

Enhancement of the Removal of Longitudinal Dunes

Ten experiments were performed with the slurry loop to test the effectiveness of the cationic surfactant

Table 2. Test reproducibility. Deposition of longitudinal wave sand dunes (big dunes) according to the standard procedure

Run no.	Sand size (mesh)	Time (min)	Velocity (m/s)	Non depo sand (%)	Depo sand (%)	Recovery (%)	Loss (%)
34	70-140	10	0.20	12.5	86.2	98.7	1.3
35	-	10	0.20	15.5	82.4	96.9	3.1
36	-	10	0.20	13.11	82.25	95.36	4.64
37	-	10	0.15	26.33	68.71	95.04	4.95
38	Art Ath	10	0.20	15.9	74.81	90.71	9.29
39	-	10	0.15	14.9	74.83	89.63	10.37
40	40-70	10	0.20	0.2			
41	40-70	10	0.25	11.50	85.33	96.84	3.16
42	40-70	20	0.20	16.31	81.89	98.42	1.56
43	70-140	20	0.20	5.55	90.76	96.32	3.68
44	40-70	10	0.20	24.33	70.64	94.97	5.03
45	70-140	10	0.20	8.63	86.74	97.59	2.48
46	70-140	10	0.20	8.14	85.4	93.52	6.47
47	Art Ath	10	0.20	25.97	62.62	88.59	11.41

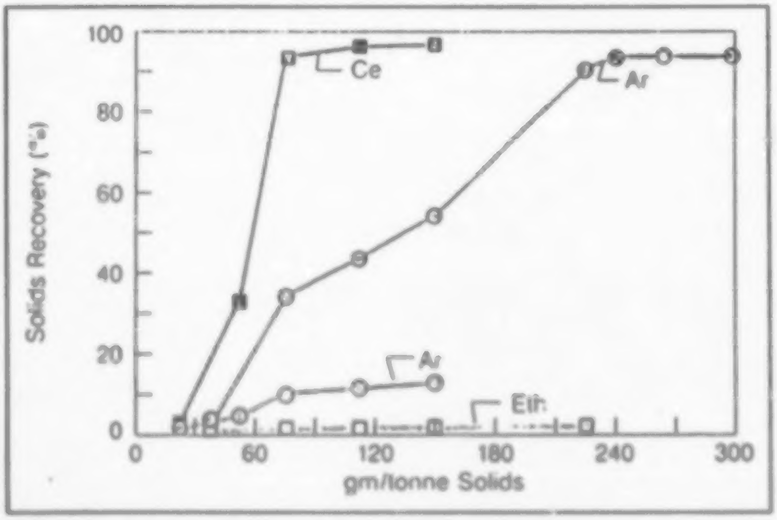


Figure 11. Efficiency of solids recovered versus the amount of collector addition for various chemicals.

and the induced flotation method for removing longitudinal waves (big dunes) deposited in a horizontal well.

Each experiment consisted of three distinct stages:

1. standard deposition of a big dune (as described previously),
2. conditioning (the preferred chemical was added in various concentrations and recirculated in the loop at 0.1 m/s for 20 min),
3. aerating and removin[illegible]00 sccm air was pumped throu[illegible] a porous sintered metallic tube covering the first 100 cm on the bottom of the glass observation zone) while water was circulated at 0.3 m/s for 20 min.

After 20 min, the velocity was increased to the maximum value of approximately 1 m/s and all sand left in the observation section of the loop was captured in a strainer, dried, and weighed. The effectiveness of the removal was therefore expressed as a percentage difference:

(4) $\text{Effectiveness} = 100\,(1 - Sp)/Si\,(\%)$

Sp is the balance of remaining sand and Si = 4500 g is the weight of sand initially introduced.

Two baseline tests (#53 and #54) were performed to observe the efficiency .f sand removal in the

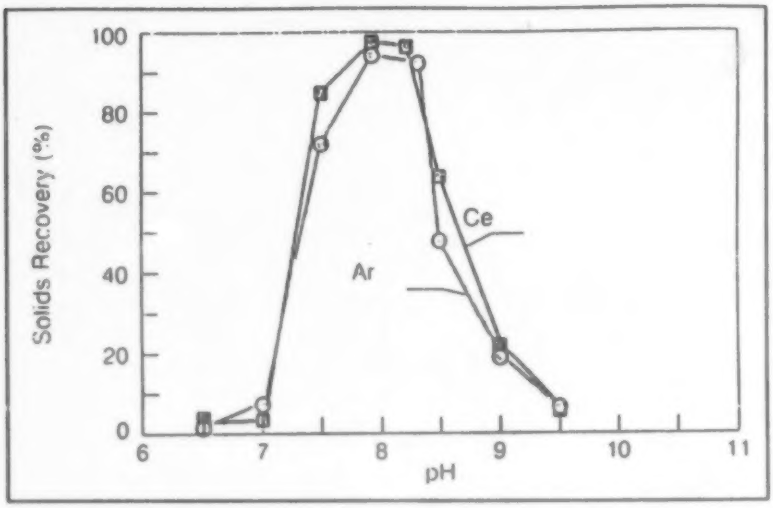


Figure 12. Influence of fluid pH on efficiency of solids removal.

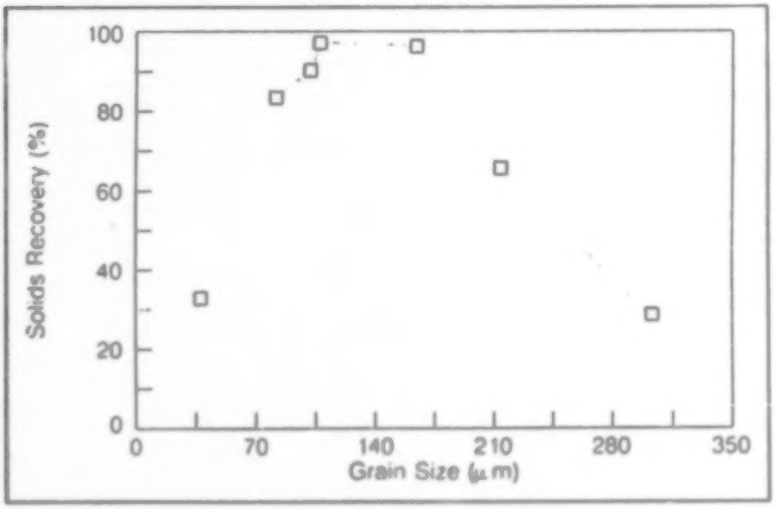


Figure 13. Efficiency of solids removal versus particle size.

absence of any flotation agent,. Run #53 used no air injection, while Run #54 was performed to assess the effect of air in the absence of chemical; both runs used water at 0.3 m/s during the removal stage. Ten tests, #51, #52 and #55–#62) using concentrations from 100 to 1160 g/tonne of solids were performed. Experimental data are summarised in Table 3 and graphically illustrated in Figure 15.

A hyperbolic model was obtained through a statistical regression

$$\text{(5)} \quad \text{Eff.} = \frac{x}{5.63 + 0.011x} (\%)$$

The model indicates that up to 70% removal is obtainable when additive in excess of 2 kg/tonne of solids is introduced. The upper recovery limit of 40% obtained with addition of chemical in excess of 2 kg/tonne appears to be more realistic.

USE OF IN SITU PRODUCED STEAM (FLASHING) FOR ACTIVATING FLOTATION

The hot fluids-contained in a horizontal production well will remain in the liquid phase providing the pressure in the well is maintained at or above the saturation pressure. Should this pressure be suddenly reduced below the saturation pressure by increasing the production rate, the liquid phase will boil, thereby producing steam in the wellbore. A lower temperature (90–70°C) vacuum system was used. Boiling was achieved at low pressure (vacuum) by exposing the fluid to vacuum reservoirs.

Experimental Procedure

Approximately 500 g of −80+100 mesh Ottawa sand was loaded into the glass tube so that it formed a layer about 1/2 inch deep on the bottom of the tube. A heater, which was wrapped around the tube, maintained the temperature at the desired level. After the chemical was injected into the tube and allowed to contact the sand for about 5 min, a vacuum was applied to the system causing the water in the tube to boil. By opening the appropriate valves, the water carrying the solids and gas bubbles flowed into the collector vessels, until the experiment was complete and solids were no longer being removed.

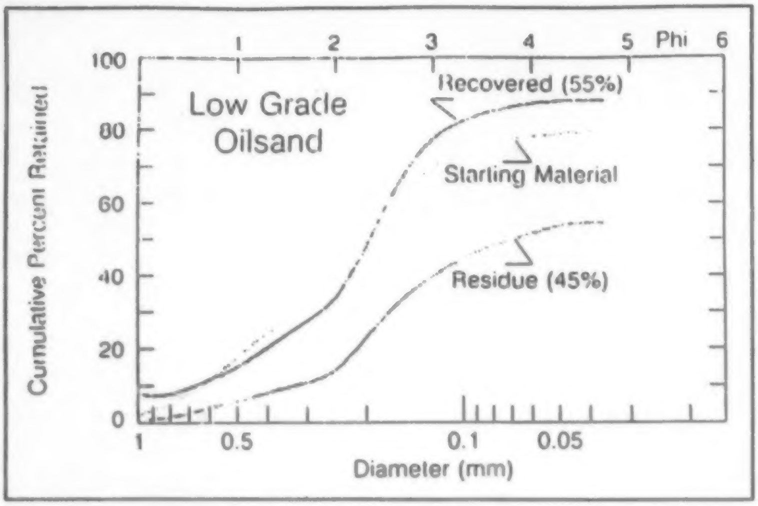


Figure 14. Efficiency of solids removal for "highgrade" oil sand.

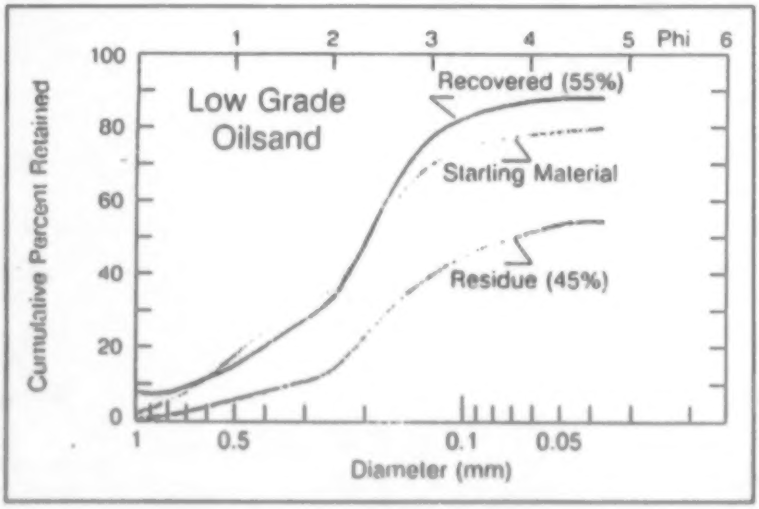


Figure 15. "Lowgrade" oil sand environment.

Results

A series of five experiments were performed to test the overall concept and to confirm that the process requires a minimum temperature for activation (50°C). The other variables (flow rate, chemical addition, and pH) were held constant, the values having been determined from the standard flotation tests described in a preceding section of this report. Results presented in Table 4 illustrate the effectiveness of in situ generation of gas bubbles in removing solids from a horizontal wellbore at relatively low bulk fluid velocities (<0.1 m/s).

CONCLUSIONS

1. A new experimental flow loop (7.62 cm diameter) was commissioned and used for the laboratory study of removing sand from horizontal wells. The experimental study indicates that the critical (slurry) deposition velocity, as derived from available slurry flow models, is not sufficient or relevant for describing the sand removal conditions and can only be used in preliminary calculations.
2. Baseline velocity regimes associated with sand transport were experimentally determined using the laboratory flow loop. The experimental data indicated that water in excess of 0.5 m/s (520 m^3/day for the typical UTF well) should be pumped for initiating the sand removal process. Slurry models applied to long, horizontal pipes indicate that high- viscosity, high-density fluids, successfully used in vertical drilling technology, will not significantly reduce the critical velocity.
3. For enhancing the effectiveness of sand removal at lower velocities, a novel method using a cationic surfactant and an induced flotation process was proposed and assessed. To achieve optimum removal conditions, the preferred surfactant, its concentration, and pH conditions, were initially established with a bench-scale flotation cell, using both sand obtained from the Athabasca deposit and clean Ottawa sand.
4. The effectiveness of a particular surfactant was further observed and quantified using a

Table 3. Summary of experimental data. The effectiveness of removal of sand accumulated in longitudinal (big) dunes at undercritical velocity using flotation technique

Test #	53[2]	54[3]	51	52	55	56	57	58
Chemical addition4 (g/tonne solids)	0	0	100	400	800	1200	1400	1400
Cost ($/tonne solids)	0	0	0.22	0.88	1.76	2.64	3.08	3.08
Deposition step[5]								
Mass deposited (g)	3407	4060	4127	3896	3858	3924	3955	4062
Percent	75.7	90.2	91.7	86.6	85.7	87.2	87.9	90.3
Removal step								
Mass removed (g)	102	236	303	621	864	861	1314	1601
Percent	3.0	5.8	7.3	15.9	22.4	22.0	33.2	39.4
Rate (g/min)	5.1	11.82	15.2	31.0	43.2	43.1	–65.7	81.4
Recovery of unremoved sand								
Mass	3252	3711	3598	3178	2895	3032	2539	2398
Percent	95.5	91.4	87.2	81.6	75.0	77.3	64.2	59.0
Cumulative percent recovered	98.5	97.2	94.5	97.5	97.4	99.3	97.4	98.4

[1] Standard test conditions using fluid velocity 0.3 m/s in the horizontal pipe for 20 minute duration. Air injection rate of 7000 sccm.
[2] Baseline removal — no chemical or air — bulk fluid velocity, only.
[3] Baseline flotation — no chemical.
[4] Chemical — CE.
[5] Total charge of sand 4500 g (#70/140 mesh silica).

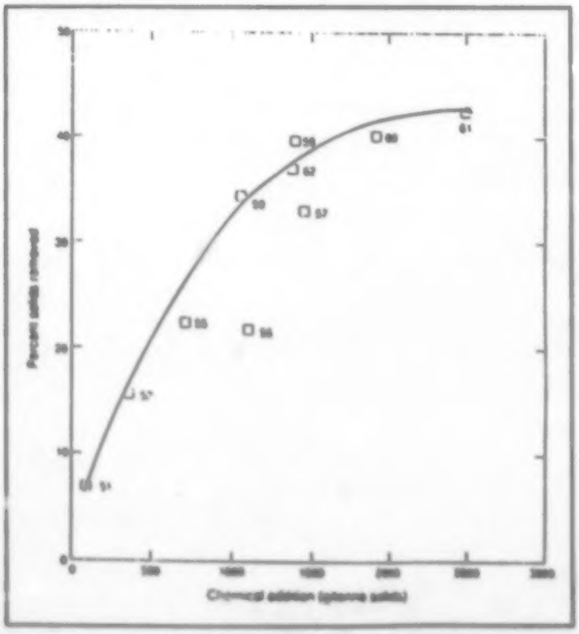


Figure 16. Efficiency of sand removal accumulated as longitudinal dunes (undercritical velocity of 0.3 m/s).

laboratory flow loop and compared to baseline (water only) removal conditions. At fluid velocities of 0.3 m/s and surfactant concentrations of 0.2% (weight of deposited solids) more than 40% of accumulated sand was removed. For a field-scale situation, up to 64% of accumulated sand would be removed using a two-step operation would require approximately 3.2 kg of surfactant/tonne of solids accumulated.

5. Equally, it was found that the removal process can be achieved using either a steam or gas bubble environment. It was found that high steam temperature conditions will not reduce the process effectiveness (for the particular surfactant selected).

ACKNOWLEDGEMENTS

The authors wish to than ARC and AOSTRA for permission to publish the paper.

Table 4. Experimental results – simulated flashing

Run #	Temp (°C)	Fluid velocity (cm/sec)	Chemical addition (g/tonne solids)	% recovery
1	24	3	0	0
2	32	3	100	0.6
3	40	3	100	0.8
4	50	3	100	74.3
5	70	3	100	75.6

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A Study of Antiplug Agents Used for Steam-Soaking Wells

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ABSTRACT

Most reservoir rocks in the Liaohe field are water sensitive, because the clay minerals in rocks contain significant amount of montmorillonite. Also, the heavy crude with asphaltene in the reservoir and the contamination of the drilling mud caused wellbore damage problems, which seriously affected the stimulation efficiency by steam soaking. This paper presents a study of an antiplug agent, which is a combination of ARP-8801 and BJ-30, used in the reservoirs of Liaohe field. This agent could effectively remove the organic and non-organic materials from the wellbore area, thus, it could increase reservoir permeability and decrease the steam injection pressure. Since April 1989, the said chemicals were tested in 21 wells at Block Du-48 of Liaohe field. According to the results, using this antiplug agent with steam injection not only increased oil production and oil steam ratio, but also prolonged the oil production period. Consequently, for these steam stimulation projects, the production performance and project economics were significantly improved.

OIL RESERVOIRS

Heavy oil in Block Du-48 of the Liaohe field is produced from monoclinal reservoirs, which has four zones with depth between 900 to 1400 meters. The principal oil zones are Du-0 and Du-1, in that 50 meters intervals, porosity and air permeability ranges 0.24–0.29, and 0.56–1.79 μm^2 respectively. The reservoir rock is basically sandstone with gravel, and contains feldspars of 45%, quartz of 30–40%, and shale of 7.1–13% (average 11.7%). Montmorillonite, which is sensitive to water, is the major component ranging 66.4 to 82.9% in the clay minerals. The produced oil is viscous with specific gravity of 0.9566 to 0.9611, and dead oil viscosity of 4,537 mPa·s at 50°C. Also this crude contains asphaltene in average of 44.26% (maximum 56.3%) and wax of 12%.

Since 1988, 160 wells were drilled, in which, 148 wells were productive by steam stimulation. The average daily oil rate at the end of 1989 was 9.75 tonnes from 120 wells, and cumulative oil production was 453,300 tonnes. As respect of steam injection, 328 cycles were conducted on 149 wells, cumulative steam of 708,020 tonnes have been injected with average daily rate of 0.64 tonnes per well. In viewing this rate, obviously, the injection performance was not in good shape. Thus, certain stimulation jobs such as acidizing, diesel, and hydroxy aluminum squeeze, as well as water injection before steaming were carried out in the Du-48 wells. These, however, did not improve steam injectivity. As a result, oil production and normal field operation suffered. The studies indicated that these problems are primarily due to the formation plugging in the wellbore area by the damage from the following:

1. Drilling mud contamination

   During well drilling in this field, the specific gravity of drilling mud was higher than the designed value in 27 wells (34% of 79 wells). In certain cases, it reached to 1.2 to 1.4. The over pressure in the mud column could force some organic and non-organic materials moving from mud into formation and significantly reduce reservoir permeability.

2. Asphaltene effect

   Because of changes of temperature and pressure in the wellbore area, steam cracking and distillation would not only generate light hydrocarbon gases, but also form asphaltene and carbon residues. Such large molecular, viscous, and polarized asphaltene could stick together with the solids from the drilling mud or with the clay minerals in the formation. These hard and stable mixtures could not be dissolved in water nor in acids, nor would it melt at a high temperature. It is this material, which is responsible for plugging the perforations in the wellbore.

3. Montmorillonite hydration causes clay particles swollen andĭ ĭĭmigrationĭ A study of antiplug agents BJ-30 (organic) and APR-8801 (acidic) resulted in field application to solve the low steam injectivity problems in reservoir Du-48. Since April, 1989, we started field tests of these agents on 21 wells. Up to date, the outcome from 18 wells indicates that an average daily oil increase after using the antiplug agents was 9.77 tonnes and incremental oil was 17,805.4 tonnes. These chemicals certainly played strong antiplug roles in reservoirs and improved steam stimulation performance.

MECHANISMS OF ANTIPLUG ACTION IN RESERVOIRS

The use of chemicals BJ-30 and APR-8801 as an antiplug agent in the steam soaking wells of the Du-48 reservoirs has following reasons:

1. BJ-30 is an organic solvent. When it takes action in reservoirs, it has good penetrative, dispersive, dampening, and dissoluble abilities. For field practice, BJ-30 is firstly injected into the formation around the wellbore area. It would penetrate into the interface between asphaltene and reservoir rock, and then wash off asphaltene to dissolve it. Finally, it clears up the rock surface. These procedures are effective to remove the organic plugging stuff from the flow paths, and the residuals will be further treated by the chemical APR-8801.

2. APR-8801 is an acidic antiplug agent with a main component of mud acid. The other ingredients are clay stabilizer (organic cation-ion compound), non-ionic anti-emulsion agent, defoaming agent, and corrosion inhibitor. This antiplug agent with strong power to dissolve shale, calcareous, irony, and siliceous matters could be effective to open up the obstructed flow paths in reservoirs. In view of the significant amount of asphaltene with large molecular, and strong polarity in the heavy crude, the acidic APR-8801 mixed with formation water could create a stable water in oil emulsion with very high viscosity. This is due to the properties of viscous oil and the minor density difference between oil and brine. In addition, the acid solution reacting with reservoir rock should release certain amount of CO_2. This gas moves in the reservoir with the said emulsion, it would face strong flow resistance, because of the capillary and viscous force as well as the Jamin effect. For these reasons, the anti-emulsion and defoaming agents are added in the APR-8801.

The ion exchanges between the cation-ion compounds and clay minerals, hydrogen bond, static charge attraction and Van der Waals' force keep the large molecular particles sticking on the clays and develop absorption film on the layer of crystal lattice. As a result, it reduces the static repelling force between the particle and layer to enable the layers shrinking but not swelling during hydration. Furthermore, the long chains of the said compound adhere to the layers of crystal lattice forming many attachments, which would stick the clay particles together reducing the chance of dispersion and migration. These effects on clay stabilization are lasting for long time, thus, it should help steam stimulation in the water sensitive formations such as the Du-48 reservoirs.

LABORATORY TESTS

Samples

1. BJ-30 is a laboratory prepared organic solvent (surfactant) used as an antiplug agent in reservoirs.
2. APR-8801 is a mud removal acid with adding multi-purpose additives. This compound was prepared based on the optimized combination from the results of laboratory studies. The component and physical properties of these chemicals are listed in Table 1.
3. The sands and mud cake powders were obtained from cores and drilling mud of Du-48 reservoirs. These were dried, crushed and passed through 20-mesh screens. Some cores saturated with oil were cleaned by using an alcohol-benzene mixture, then dried and passed through 20-mesh screen again.

Dissolution Tests

The tests were carried out in 50°C (reservoir condition). Core and mud cake powder were put into different solutions for two hours. The residuals were taken out, dried, and weighed. The weight lost to the original weight ratio is defined as dissolubility (K), which is the degree of soluble organic or non-organic matters in that solution. The tests included:

1. Mud cake powder with organic matters were dissolved in four different solutions. The results are shown in Table 2. From which, BJ-30 exhibits highest dissolubility indicating it has more power to dissolve asphaltene.

Table 2. Dissolubility of mud-cake powder in solvents

Solvent	Dissolubility, %
Toluene	5.07
Ethylene glycol butyl (ether)	4.80
Carbon tetrachloride	6.00
BJ-30	6.59

2. The dissolubilities of clean sand powders in mud acids with different blends are presented in Figures 1 and 2 as well as in Table 3. From these, the best combination with highest dissolubility and no white sediments was selected.
3. The dissolubilities of mud cake powder in mud acids with different blend are listed in Table 4. The results are similar to those in Table 3.

Table 3. Dissolubility of clean sand in mud acids with different blends

Mud acid	Blend	Dissolubility, %	Remarks
1	A	16.63	
2	B	17.29	
3	C	20.21	
4	D	22.09	Selected blend
5	E	25.55	White sediments
6	F	31.34	White sediments

Table 1. Antiplug agents and their properties

Sample	BJ-30	ARP-8801
Basic composition	Surfactant dispersant organic solvent	Mud acid, clay stabilizer anti-emulsion agent corrosion inhibitor defoaming agent
Appearance	Yellow, viscous, semi-transparent organic solution	Light yellow, clear, transparent solution
Characteristics	Oil soluble, it doesn't mix with water stimulative smell	Strong acidic solution, it doesn't mix with oil
Specific gravity (20°C)	Greater than 1.35	Equal or greater than 1.01 (15°C)
Flash point (0°C)	Greater than 160	Greater than 60
Freezing point (0°C)	Greater than –60	Equal or less than –1.0
Remarks	With strong power to dissolve asphaltene, wax and rubber	Strong acid could dissolve shale, calcareous, irony, and siliceous inorganic matters

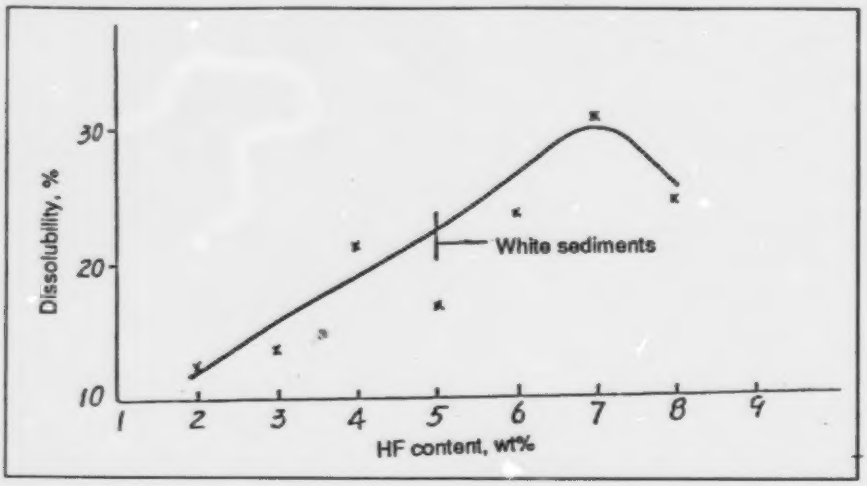

Figure 1. The dissolution of sand powders in 10% HCl mud acid.

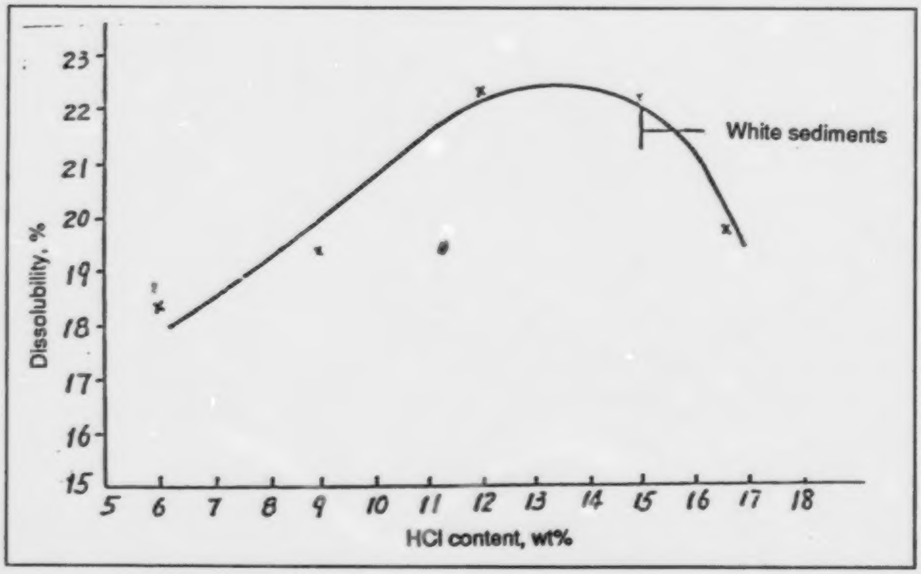

Figure 2. The dissolution of sand powders in 4% HCl mud acid.

Table 4. *Dissolubility of mud-cake powder in mud acid with D blend*

Mud acid	Blend	Dissolubility, %	Remarks
1	D	29.46	no sediments
2	D	29.60	no sediments

4. As shown in Table 5, mud acid with adding clay stabilizer, and corrosion inhibitor, did not affect the dissolubility of clean sand and mud cake powder.

Screening and Testing of Clay Stabilizers

The cleaned core powder and core samples saturated with crude were dissolved in the distilled water, which was added with different clay stabilizers. The tests were carried out for 60 days in the room condition of about 26°C in order to observe the situation of swelling and dispersion from cores. The results of rock volume changes with time for each test were determined. The purposes of this study are:

a. To compare the effectiveness of controlling swelling in solution by different clay stabilizers.

b. To compare the effectiveness of swelling control in solution by different quantity of a clay stabilizer.

The results as shown in Figure 3 indicate that the organic cation-ion compound is efficient to stabilize clay in solution and inhibit its volume expansion. With such help, the sands' swelling could be controlled within 15% of the original volume. On the other hand, the sands in distilled water might reach 100% of volume expansion. For already hydrated and enlarged sands, the clay stabilizer is still effective to retreat them in order to repress their continuous enlargement.

The dry sand sample after being soaked in distilled water and then treated with clay stabilizer, was analyzed by using X-ray diffraction method. The results indicate that Ca-type saponite was observed in the sample with the distance between layers of crystal lattice (d_{001}) as follows:

Dry test: $d_{001} = 15.24$ A°
Wet tests: soaked in distilled water, $d_{001} = 19.3$ A°
(interlayer water, 4)
treated with clay stabilizer, $d_{001} = 14.5$ A°

These sufficiently proved that after the treatment of cation-ion compound, d_{001} value of saponite was stabilized at 14.5 A°. In a comparison with the dry-test result, the crystal lattice in the shale did not expand but shrink, indicating the clay stabilizer functioned very well.

Screening and Testing of Corrosion Inhibitors

In order to prevent the mud acid corrosion against pipeline, tubing, casing, and wellhead equipment, coupon tests for several corrosion inhibitors with different blends were carried out. The results are presented in Table 6, from which, corrosion from the antiplug agent with inhibitor was only 0.68% of that due to mud acid attack.

Table 5. Dissolubility of samples in mud acid with different additives

		Dissolubility, %		
Test	Type of solution	Clean sands	Mud cake	Remarks
1	Mud acid + clay stabilizer A_1	28.38		
2	Mud acid + clay stabilizer A_2	30.54	30.46	selected blend
3	Mud acid + clay stabilizer A_3	30.45	18.26	
4	Mud acid + clay stabilizer B_1	21.88	21.04	
5	Mud acid + clay stabilizer B_2	21.16	36.67	
6	Mud acid + clay stabilizer B_3	21.19	38.54	
7	Mud acid + corrosion inhibitor C_1		26.43	
8	Mud acid + corrosion inhibitor C_2		27.80	
9	ARP-8801		20.24	Slightly affected
10	ARP-8801		24.90	Slightly affected

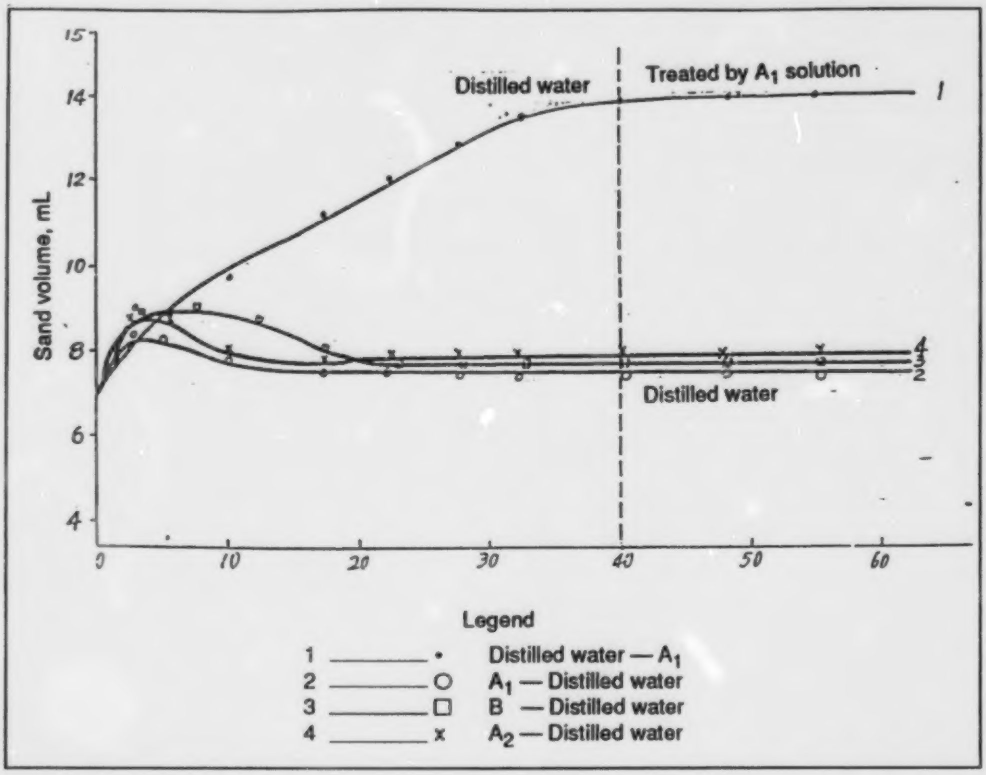

Figure 3. Sand volume expansion in solutions with different clay stabilizers (days).

Screening and Testing of Defoaming and Anti-Emulsion Agents

The reaction between mud acid and carbonates in the formation could create CO_2 bubbles, which would increase flow resistance in reservoirs and build up steam injection pressure. The tests of three defoaming agents as shown in Table 7 indicate that even with adding 0.1% of Tuman or GP could effectively reduce bubbles.

The heavy oil with high asphaltene content normally embraces many polar compounds. When these react with mud acid, it creates water in oil emulsion. Such products with high viscosity are difficult to move in reservoirs. Thus, the combined used of anti-emulsion and antiplug agents together is necessary. From the screening tests, a non-ionic surfactant was selected as an anti-emulsion agent. It exhibited good emulsion breaking power, when it works with mud acid.

***Table 6.** Iron coupon tests in solutions with and without corrosion inhibitors*

Test	Type of solution	Corrosion rate, %
1	Mud acid	6.42
2	Mud acid	5.35
3	Mud acid + inhibitor	2.51
4	Mud acid + inhibitor	2.13
5	ARP-8801	0.05
6	ARP-8801	0.03

***Table 7.** Tests of defoaming agents*

Defoaming agent	Weight %	Height of foam, mm	
		Beginning	2 minutes late
Mud acid	0.0	120	60–80
GP	0.1	60	30
GPE	0.1	120	60–80
Tuman	0.1	60	30

Cores Flood Tests

The artificial cores with diameter of 2.64 cm., and length of 4.5–4.8 cm. were made of high pressure compressed reservoir rock powders. These powders were cleaned sands or sands saturated with crude oil. The artificial cores still retained more or less the similar type of rocks, kinds of clay minerals, ranges of air permeability, and amounts of asphaltene in the original oil. After the air permeability, K_g was measured, the stable permeability to water with 15% NaCl was then obtained on these cores, K_o and P_o were finally recorded as permeability to oil and initial pressure. The procedures of the flood tests were:

(1) 15% NaCl (K_o) → distilled water (K_1) → solutions with different clay stabilizers (K_2) → distilled water (K_3) → 15% NaCl (K_4)

(2) 15% NaCl (K_o) → solutions with different clay stabilizers (K_2) → distilled water (K_3) → 15% NaCl (K_4)

(3) 15% NaCl (K_o) → APR-8801 (K_2) → distilled water (K_3) → 15% NaCl (K_4)

By using the ratios of the measured K_1 (K_1/K_0, K_2/K_0, ...) and P_1 (P_1/P_0, P_2/P_0, ...) to determine the conditions of permeability decrease and the pressure increase in these cores, for instance, the decreasing K_1/K_0 and increasing P_1/P_0 indicate the serious plugging problem. On the contrary, the antiplug agents worked well. The tests results are shown in Table 8, and part of the data (the changes of K_1/K_0 and P_1/P_0 with time), is also presented in Figures 4, 5 and 6. From these, we conclude that solution of organic cation-ion compound should be injected into the water sensitive Liaohe reservoirs as a pre-treatment. This could inhibit the clay minerals expansion, control the particles movement, and ultimately prevent the formation damage. Also APR-8801 used as an antiplug agent in the Liaohe reservoirs was effective to regain rock permeabilities in these formations. It is believed that laboratory results provide the solid foundation for field tests.

FIELD TESTS

Since April, 1989, the combined use of APR-8801 and BJ-30 as an antiplug agent has been successfully tested in 21 wells of the Shu Guang Du-48 block reservoirs.

A. Tested wells selection Reservoir properties in these wells must be above the average, and these candidates had either abnormal production during steam stimulation or had been shut down due to operational problems. The reservoir and test data of these wells are presented in Table 9.

B. Test procedures and the use of antiplug agents The required BJ-30 was calculated based on wellbore space with the height slightly greater than formation thickness. This with the addition of extra volume for squeeze into formation is about 1.5 to 2.0 tonnes per well.

Table 8. Data of core flood tests

Core sample	Core type	Initial ion type	Treated with chemicals	Nitrogen permeability $\mu m^2 \times 10^{-3}$	Initial permeability $\mu m^2 \times 10^{-3}$	Distilled water				Distilled water		15% NaCl water	
						K_1/K_0	P_1/P_0	K_2/K_0	P_2/P_0	K_3/K_0	P_3/P_0	K_4/K_0	P_4/P_0
3	clean sands	I	A										
5	"	I	B										
2	"	II	A										
6	"	II	B										
7	"	II	C										
A	"	III	ARP-8801										
8	contains oil	IV	ARP-8801					•		•		•	
9	"	II	A					•		•		•	

* Assuming $K_0 = 1.0$

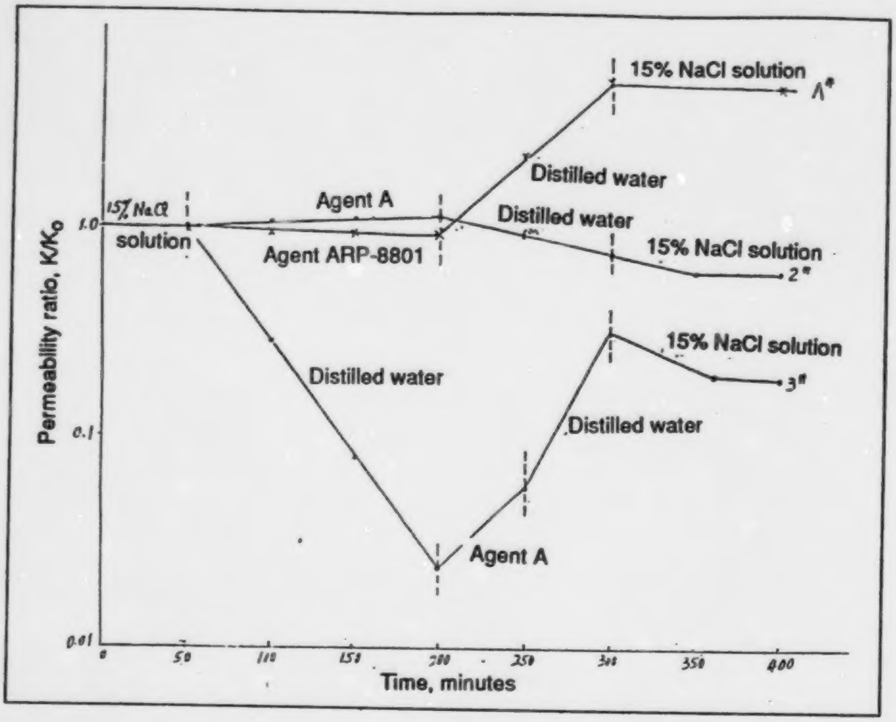

Figure 4. Changes of permeability ratio under different injection strategies.

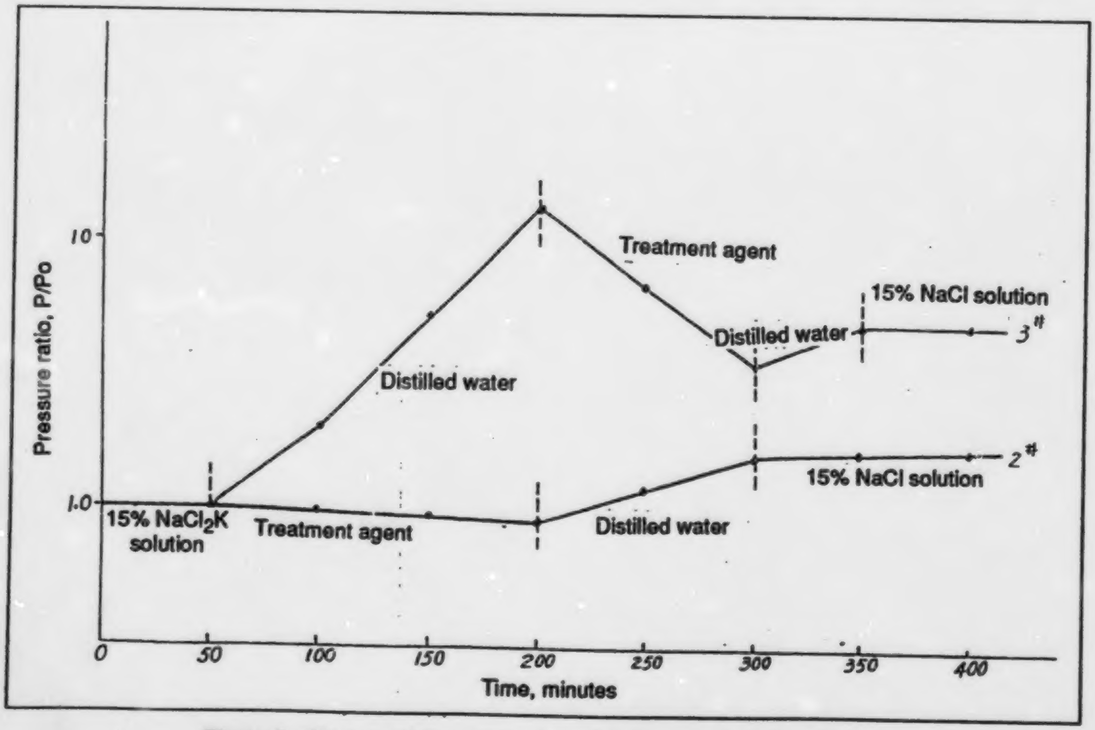

Figure 5. Changes of pressure ratio under different injection strategies.

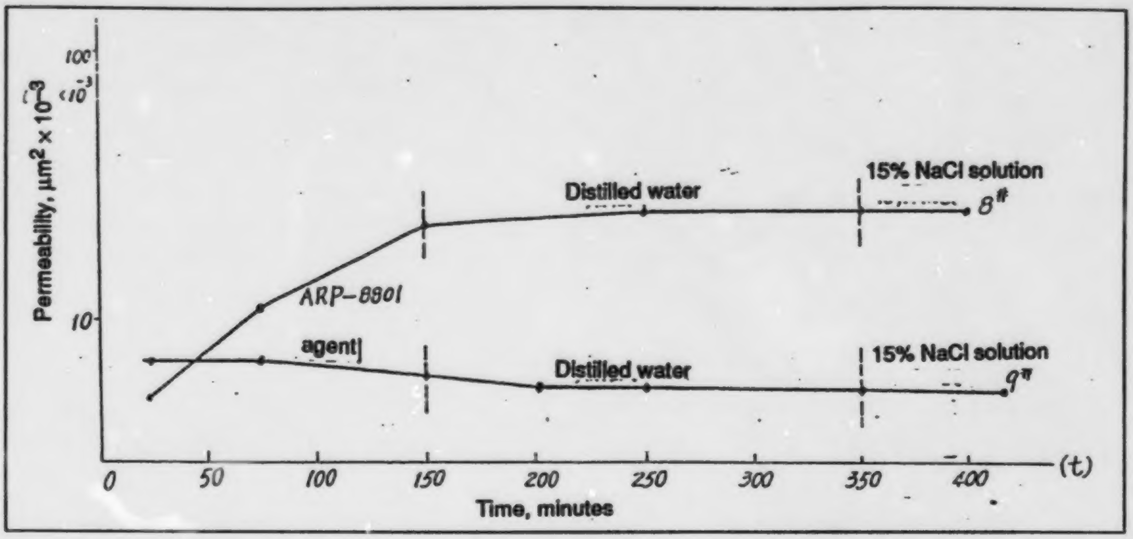

Figure 6. Permeability changes in the porous core samples under different injection strategies.

The required volume of APR-8801 was estimated based upon

$$V = r^2 * h * 0$$

where r = treated radius in formation is about 1.5 meters

h = effective thickness of formation

0= porosity

These chemicals were prepared and stored in the tank cars, and sent to well sites for injection.

Testing Procedure

1. Running tubing
2. Washing wellbore
3. Using 1.0% NaCl or NH_4 solution as a displacing fluid to transpose BJ-30 to the wellbore, the well was shut in for 24 hours.
4. Squeezing the required volume of APR-8801 into formation, the displacing fluid was water with 1.0% clay stabilizer. The well was shut in for ten hours in order to keep the antiplug agent working effectively in the reservoir.
5. Injecting steam, which could push BJ-30 and APR-8801 further deep into reservoir.

C. Results analysis

Production performance before and after tests on 21 wells is presented in Table 10. In review of such data, we observed:

1. Injection of antiplug agents with steam not only increased daily oil rate on wells, but also rehabilitated some disabled (shut-in) wells for normal production.

Up to May, 1990, oil production from 20 wells after tests indicates that significant oil-rate gain was observed on 18 wells (Table 11). In which, wells with more than 10 tonnes of daily oil increase is 55.5%. The average rise of daily oil rate was 9.77 tonnes per well, and total incremental oil was 17,805.4 tonnes. Typical production response was shown on wells as follows:

- Well 15224 had permeability of 1980.9 $\mu m^2 * 10^3$ in reservoir and started production in November 1989. It produced with average oil rate of 8.6 tonnes/d during the first 91 days, but the rate decreased to 3.1 tonnes/d before the chemical injection. It is believed this production decline is simply due to formation damage. However, after the treatment with squeeze of APR-8801 in the formation, this well produced 18.8 tonnes/d by flowing for 109 days, and the daily oil increase is about 15.7%.

- Well 14624 began production in October 1988 and produced 954 tonnes of oil in 462 days with an Oil-steam ratio of 0.2066. Although this well possesses reasonably good permeability in reservoir (638 $\mu m^2 * 10^3$), it was still troubled with abnormal operation and low oil rate, and was subsequently to be forced shut in. After the squeeze of APR-8801, well 14624 produced 435 tonnes of oil in 73 days and regained normal oil production.
- Well 152026 (reservoir permeability: 345 $\mu m^2 * 10^3$) was steamed four times and was shut down before antiplug treatment. The results are:

Cycle	Flowing d.	Pumping d.	Total oil tonnes
1	17	–	173
2	40	–	265
3 & 4	–	8.1	30
		Total oil	469 tonnes
		Total steam	8061 tonnes
		Operation	272 days

After the squeeze of APR-8801 and steam injection of 2436 tonnes in this reservoir, the said well produced 3733 tonnes of oil within 264 days.

- Well 14818 started operation in February 1989 and was shut in after two cycles of steam stimulation, since no oil was produced. However, injection of antiplug agents with steam, and even retesting through the reperforated casing did not improve producing performance. This might be caused by geological abnormities in reservoir.
- After the treatment with antiplug agents and steam injection, well 150026 encountered the sand problems during well flowing. Workover is required for this well.

2. Antiplug treatment in reservoir improved steam stimulation performance

In a comparison of production performance on wells before and after the antiplug treatment, Table 10 shows comparative information from 21 wells with injection of APR-8801. In this Table, the first 5 wells with one complete steaming cycle are selected for further comparison with that from 81 wells, those had no antiplug treatment. The results are presented in Table 12. In reviewing the data, wells with the mentioned treatment had significant improvement in steam stimulation performance. These include:

- The period of steaming cycle was prolonged from 121.1 days to 218 days, the increase is 1.8 times.
- Oil production per cycle escalated from 821.3 tonnes to 2869 tonnes, the improvement is 3.5 times.
- Oil-steam ratio jumped from 0.4131 to 1.1718 indicating the significant boost of steaming efficiency.
- The average daily oil rate per well raised from 6.78 tonnes to 13.88 tonnes, the change is 2.05 times.
- The incremental oil from 5 wells (Table 10) was 12,278 tonnes. Based on official oil price in China, the value of such oil is 4.3 times of the total costs of the said chemicals and treatment operation.

CONCLUSIONS

1. The combined action of APR-8801 and BJ-30 as an antiplug agent in reservoirs has certain advantages:
    a. It is capable to dissolve asphaltene, shale, calcareous, irony, and siliceous plugging materials in the formation.
    b. It could stabilize the clay particles to control their expansion, dispersion, and migration.
    c. It prevents the oil-water emulsion and bubbles from growing to maintain reservoir permeability for fluids flow.
2. The field operation of injecting the said antiplug agent into reservoirs is simple and easy.
3. To recover heavy oil in the water sensitive formations by steam stimulation, the combined use of APR-8801 and BJ-30 could be effective to

prevent formation plugging, increase oil rates, improve stimulation efficiency, and enhance project economics.

ACKNOWLEDGMENTS

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PUMPING TECHNOLOGY OF DIRECTIONAL CLUSTER WELLS FOR SHALLOW HEAVY OIL RESERVOIRS

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ABSTRACT

This paper gives the details of developing the shallow directional cluster of heavy oil wells and their pumping operation at the Jinglou oil field of Henan. Design considerations related to the hydraulic recoil heavy oil pump, supplementary tools, and downhole tubing string as well as sucker rods are discussed. The developed technique suited for pumping heavy oil from the mentioned wells is presented in this paper. It also briefly describes the results of field operation.

INTRODUCTION

The heavy oil reservoirs at Henan are primarily located in the regions of Gucheng and Jinglou. Because of dense population, limited land for industry use restricted regular well drilling. Thus, the development of directional cluster wells to produce heavy oil from this field is necessary.

Drilling and completion of slant-vertical wells in the Gucheng cluster well group was accomplished in March 1990. Preparation for a pilot test is still underway. However, the said operation in the Jinglou cluster well group was ended in November 1988, and the steam stimulation test began in December 1989.

In China, there was no previous experience to develop such a shallow heavy oil pool as that in Jinglou oil field by drilling directional cluster wells. In concern of some technical problems encountered during pumping operation, we used hydraulic recoil pumps for the said practices. Also sucker rods, tubing string as well as supplementary tools were specially designed for this purpose. After nine months of steam stimulation tests in this field, the results provided valuable information, which could be applied to future development of this type of oil reservoirs on a large scale. The technique of this pumping system have proven feasible to handle field problems through the tests.

DESCRIPTION OF THE JINGLOU DIRECTIONAL CLUSTER WELLS

The reservoir in the Jinglou field is sandstone. Its depth ranges from 378.7 to 409.55 meters, and the average pay is 6.58 meters. The reservoir temperature is low; its correlation with depth based on log data is expressed as:

$$T = 15.5351 + 0.013 * H$$

where T = formation temperature, °C
H = vertical depth of formation, m.

The reservoir temperature calculated from this equation varies between 32.14 to 33.16°C. The viscosity-temperature curve for the crude in this area shows that oil viscosity is sensitive to the temperature changes. Figure 1 demonstrates that dead oil viscosity decreases to 14% of its original level when the temperature increases from 30 to 50°C. The same degree of oil viscosity decrease exists as the temperature further escalates to 100°C. The oil properties under reservoir conditions are listed as follows:

• Dead oil density	0.9375-0.9595 g/cm^3
• Oil viscosity	6,000–8,000 mPa·s
• Colloidal asphalt content	35.24–42.65%
• Wax content	6.01–6.22%
• Sulphur content	0.21–0.32%
• Freezing point	5–19°C

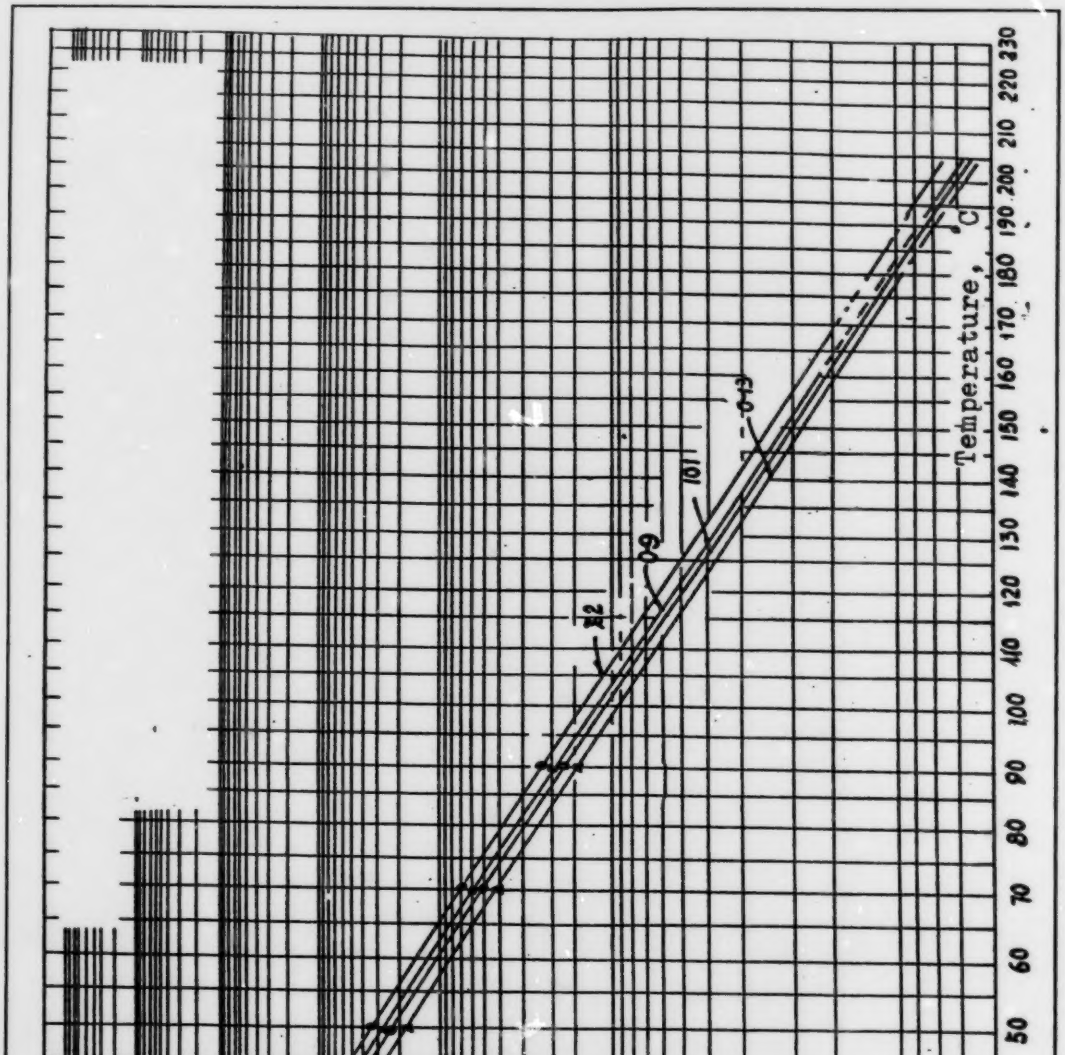


Figure 1. Viscosity-temperature curves of the oil from the Polit area in unit zero of Jinglou Oilfield.

The Jinglou cluster well group has eight wells. One was drilled vertically while the others were directional. The wells' site on the surface were arranged in line in the same direction with a five-meter distance between wells. In the formation, however, a five-spot pattern with well spacing of 100 meters was developed. After all wells were drilled and completed as shown in Figure 2, the actual distance between producer and injector ranged from 89 to 113 meters. For these drillings some important parameters are summarized below:

• Vertical depth at the target center	384 to 413 m
• Maximum horizontal displacement	92.39–142.97 m
• Depth of the building angle point	0–70 m
• Maximum deviation angle	17.5–31 degree
• Angle building rate	10–15 degrees/100 m

For directionally drilled wells, the deviation and azimuth angles varied considerably in each well. For example, when well 0503 was drilled from 0 to 25 meters, the corresponding deviation angle was 0° 30' to 9°, and the change of the deviation angle reached 8° 30'/m. For well 0406, the corresponding azimuth angle changed from 0°, 5°, 20°, 60 degrees at the depth of 0, 25, 50, 75 meters, and the maximum variation was 40°/25 m. Also the changes of both azimuth and deviation angles created an "S" type twist in well 0507, in which, the corresponding azimuth angle varied from 0, 25, 20, 25 degrees at the depth of 0, 25, 50, 75 meters.

PUMPING TECHNOLOGY

Several operational problems were experienced in this group of wells to produce heavy oil in Jinglou field.

1. For a shallow heavy oil reservoir, pumps can not be set deep. When sucker rods are running downwards against the viscous oil in the wellbore, the downhole strings are buoyant. This will cause the sucker rod string to have unsynchronized movement with the donkey head.
2. The well condition in the directionally drilled shallow wells will accelerate sucker rods and tubings wear, which increases strain and causes fatigue to the rods.
3. The well deviation would force the pump to stay at a inclined position in the wellbore, this could cause the valve ball to leave the valve seat in the pump, and would result in fluid leakage and low pumping efficiency.

Since the irretrieved tubing string for injection/pumping operation is required for steam stimulation in the Jinglou field with a thin oil pay, this, together with the above problems forced us to rethink the necessary changes. Consequently, we developed new pumping techniques including the designs of a hydraulic recoil heavy oil pump, sucker rods, tubing string, and supplementary tools.

Hydraulic Recoil Pump Designed for Slant Holes

This pump, as shown in Figure 3, consists of a pump barrel, plunger, discharge valve, suction valve, seal sub, and solid rod. The pump has the following features.

A hydraulic recoil action during pumping. On the down stroke, the pump suction valve is closed while the discharge valve is open. A hydraulic pressure is thus exerted on the solid rod creating a downwards action, which is called the hydraulic recoil. This action helps to overcome the drag force caused by the friction between the viscous oil and plunger as well as sucker rods. Also the coil could prevent the rods from helical buckling and increase the effective stroke of the pump.

When the fraction drags on the plunger and discharge valve are not considered, the hydraulic recoil is given by

$$\begin{aligned} P_f &= [P_t * A_p (A_p - A_r) * P_t - P_c * A_r] * 10^6 \\ &= (P_t - P_c) * A_r * 10^6 \end{aligned}$$

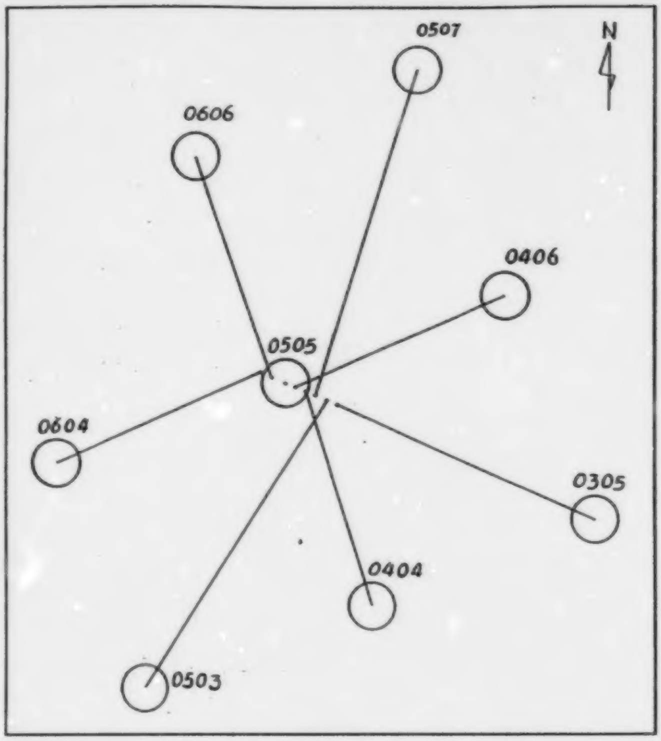


Figure 2. Horizontal projection drawing of the shallow cluster well group.

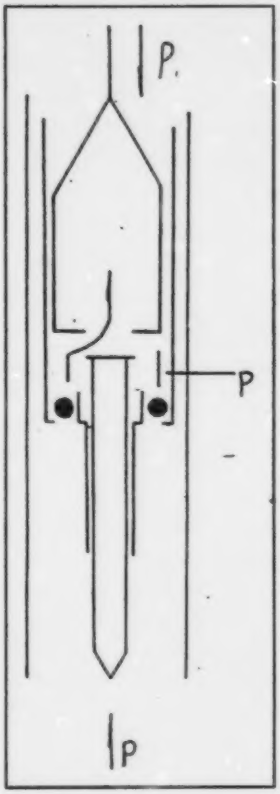


Figure 3. Scheme of pump for heavy oil.

where: P_f = hydraulic recoil on the down stroke, N

A_p = cross sectional area of plunger, m^2

P_t = pressure of liquid at plunger in tubing, MPa

A_r = cross sectional area of solid rod, m^2

P_c = pressure of annulus liquid at the solid rod, MPa

The above equation indicates that on the down stroke, the hydraulic recoil is related to the differential pressure between tubing and casing, and the cross sectional area of the solid rod.

It satisfies the irretrieved tubing string for injection/pumping operation. Before injecting steam into a well with this pumping system, the sucker rod should be pulled upwards slightly in order to lift the plunger out of the pump barrel, and the solid rod out of the seal sub. Thus when the tubing is opened to the casing, the injected steam can enter the formation through the barrel. When steam injection is over, we could reconnect the plunger into the barrel and the solid rod into the sub by using the surface lifting equipment. As the pump touches the standing valve, the distance between the piston and the valve should be adjusted to prevent shock during pumping operation. In general, as long as the pump is not damaged, this kind of injection/pumping conversion can be repeated many times.

A large open area in the suction valve can reduce flow resistance and improve the degree of fill-up. The pump was designed with several valves around the suction body so the downhole fluids could enter the pump chamber through these valves. The total opening area for fluids to flow thru is 17.9 cm^2, which is 3.2 times that in the conventional heavy oil pumps. Also, the length of the flow channel (32 mm) is much shorter than that in the conventional one. This design obviously helps to increase the fill-up efficiency.

It reduces valve leakage caused by well deviation. In conventional pumps, there is a large radial clearance in the valve between the ball and the housing. When the pump is inclined, the ball may stay on the shoulder formed by the housing and valve seat, this would result in time lag of valve closing and fluid losses.

Assuming a valve was initially in an inclined position, and the ball was out of the seat staying on the shoulder. Figure 4 shows a transient moment, when the ball starts moving back into the seat due to the valve changing its position from inclined to vertical. In this situation, the vertical line HG intersects the center line HE of the valve at H to develop the seating critical angle (β), thus, we have:

- HE, HG, and A represent valve center line, vertical line, and ball center, respectively.
- The line AD is parallel to the lines BF and HE. The line AB is parallel to the line EF.
- FE = 1/2 (inner wall diameter of valve housing, mm) = 1/2 (D_h).
- DF = 1/2 (diameter of valve ball, mm) = 1/2 (D_b).
- CE = 1/2 (diameter of seat mouth, mm) = 1/2 (D_s).
- The valve seating critical angle (β, degree) is determined by:

$$\beta = \arcsin \left[1 - \frac{D_h - D_s}{D_L} \right]$$

In general, the deviation angle in conventional wells should not be greater than the seating critical angle of the valve. However, the valve could be redesigned with a larger critical angle to suit the needs in any slant holes.

Theoretical pump displacement. The pump with a cylindrical chamber consists of a barrel, valve body, seal sub, plunger, and solid rod. The theoretical pump displacement, Q_t, (m^3/d) is:

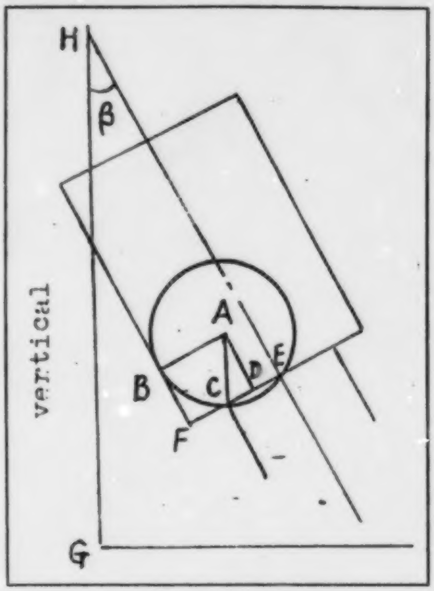


Figure 4. Calculation chart for the valve.

$$Q_t = 1{,}440 * (A_p - A_r) * s * n$$

where s = stroke, m

n = stroke per minute, spm

Designs of Sucker Rods, Tubing Strings, and Supplementary Tools

Anti-release rod device (Figure 6). This device was designed to eliminate sucker rod string helical buckling and reduce unthreading. For the special situations of unthreading the sucker rods, the unthreading anti-release mechanism was used.

Sucker rods shock absorber (Figure 7). This equipment can be used to reduce the possibility breaking sucker rods strings by a loading or unloading shock.

Roller collar (Figure 8). The roller collar is used to change sliding friction between rods and the inner tubing well to rolling friction.

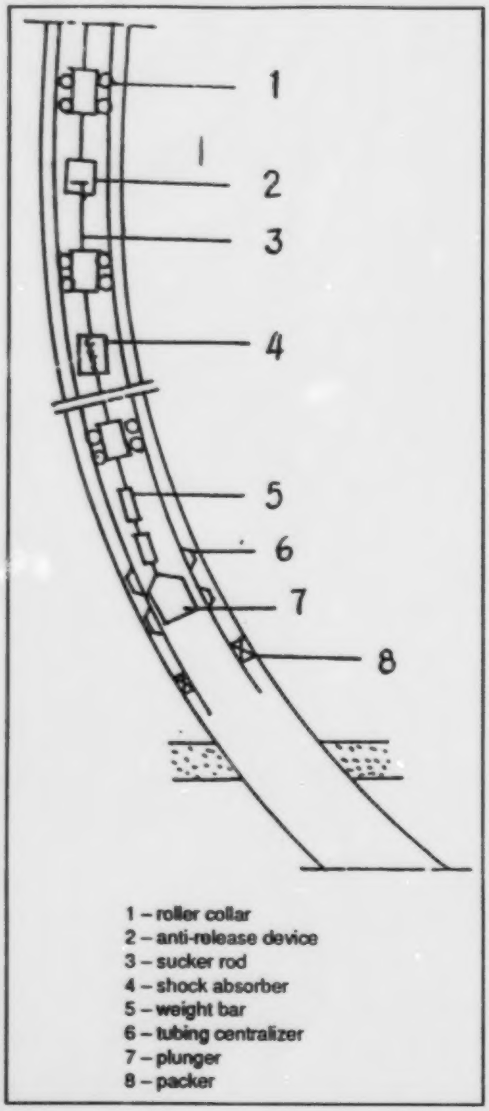

1
2
3
4
5
6
7
8
1 – roller collar
2 – anti-release device
3 – sucker rod
4 – shock absorber
5 – weight bar
6 – tubing centralizer
7 – plunger
8 – packer

Figure 5. Schematic view of rod and tubing string assembly.

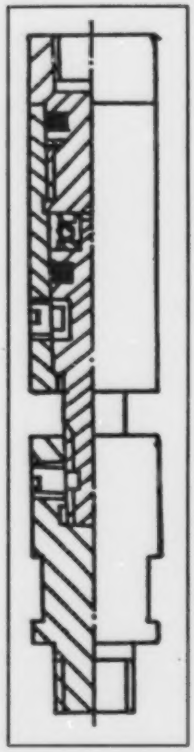


Figure 6. Sucker rod anti-release device.

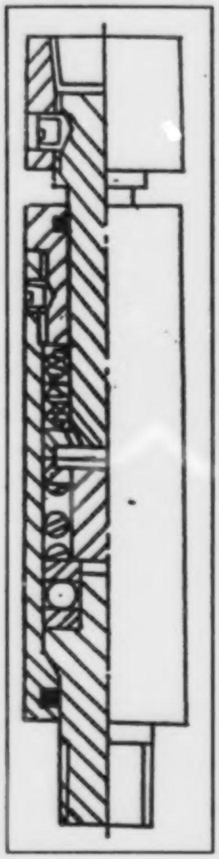


Figure 7. Shock absorber.

The sealed roll bearing was utilized to reduce the friction between the roller and shaft and to prevent sand problems. The number of roller collars installed on the rod string depends on the length of the tubing string, the change of well deviation angle, and the results calculated from the following equations.

As shown in Figure 9, a part of tubing section is intersected by the sucker rod with its outer round surface of the collar touching the inner tubing well. Thus, the corresponding angle (β, degree) at the center in the curved section of tubing is determined from (1), and the sucker rod length between the two roller collars is calculated from (2).

$$(1)\quad \frac{32}{A_r}\left(\frac{\alpha}{4}\right) - A'B' \cdot \alpha \cdot \frac{10^{-3}}{\theta} = 0$$

$$(2)\quad L = d \cdot \frac{10^{-3}}{A_r} \cdot \left(\frac{\alpha}{4}\right)$$

where L = calculated length of sucker rod between the two roller collars, m

θ = corresponding angle at the center in the curved section of tubing, degree

α = angle at the center, degree

d = difference between inner tubing diameter and outer roller collar diameter, degree

A'B' = measured length in the curved tubing section, m.

Tubing Centralizer (Figure 10)

Well deviations create a complex situation on the pump in which the plunger is more difficult to get into the barrel. The installation of centralizers on each side of the barrel guides the plunger into the barrel easily and decreases the resistance between the plunger and barrel as well.

Thermal Packer and Telescopic Tube (Figures 11 and 12)

A hydraulic slip thermal packer was developed and used in this field in order to reduce heat losses and shut off water in wells. Also a telescopic tube was installed in the tubing string to compensate the tubing's expansion and contraction due to significant temperature changes.

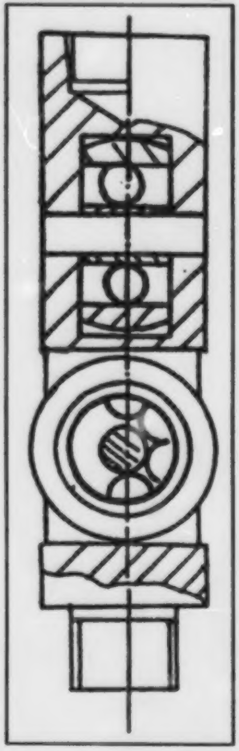


Figure 8. Roller collar.

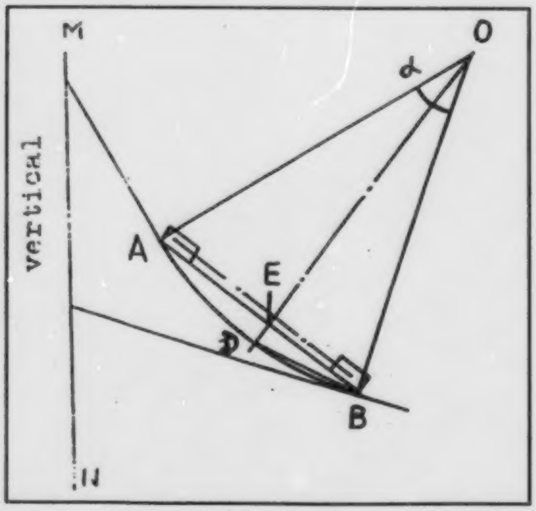


Figure 9. Chart for calculating number of the roller collar.

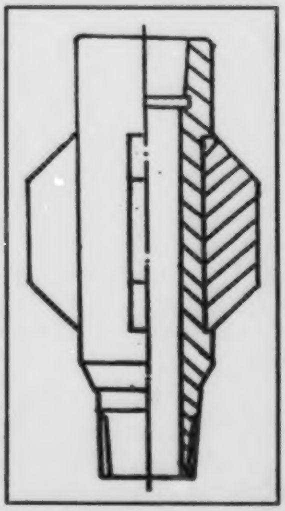


Figure 10. Tubing centralizer.

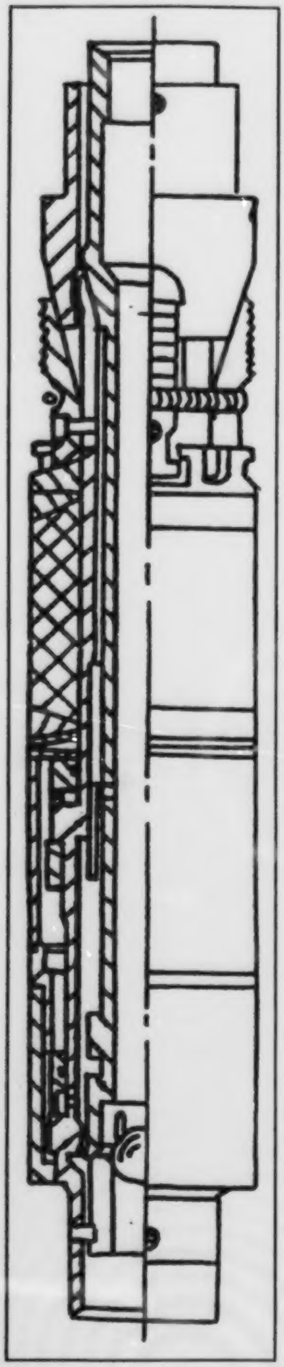


Figure 11. Thermal packer.

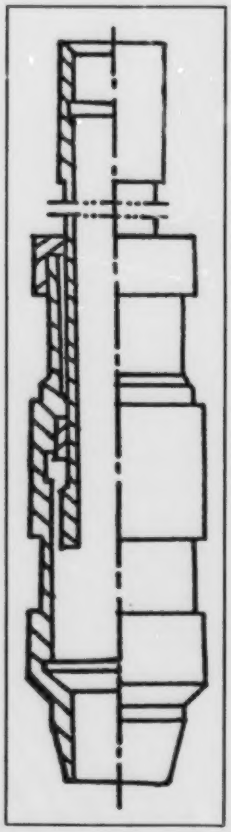


Figure 12. Telescoping unit.

FIELD RESULTS

The above description of pumping technology has been successfully applied in the Jinglou cluster well group to produce heavy oil by steam stimulation. The operation on the first well from October 1989 to September 1990 indicated that alternating injection/pumping worked very well. The sucker rods as well as the tubing string were still in good condition, and the hydraulic recoil pump achieved the objectives of the original design. In total, seven wells operated for four cycles with an average pumping efficiency of 48.7%. By the end of August 1990, the cumulative oil production was 8331 tonnes.

During production, the measured loads on the polished rod in the Jinglou cluster wells were compared with those from calculations. Taking well 0606 for example, pumping well data is shown as follows:

- Flowing liquid level (H_f) = 300 m
- Wellhead temperature = 58°C
- Stroke (s) = 2 m
- Strokes per minute (n) = 7 spm
- Diameter of sucker rod = 7/8"
- Pump section depth (H_p) = 390 m
- Weight of weigh bar (W_v) = 2100 N

From these, the load on the polished rod (P) is calculated from the equation below.

$$P = \left(1 + s \cdot \frac{n}{137}\right) \cdot \left\{\left[W_v + W_c + W_{vc} \cdot (\cos\beta \pm f \cdot \sin\rho) \cdot X_o \pm f \cdot A \cdot \rho\right]\right\} + \left(W_p + F\right) \cdot X_o \pm f \cdot A \cdot \beta$$

where $A = [1 + \sin^2\beta * (\Delta\psi/\Delta\beta)^2]^{1/2}$

W_v = sucker rod weight (air) in the vertical well section, N

W_c = sucker rod weight (air) in the curved well section, N

W_{vc} = sucker rod weight (air) in the vertical and curved sections, N

f = friction coefficient (0.25), dimensionless da/db = ratio of cumulative change of azimuth angle to the difference of well deviation angle in the curved well section, dimensionless

F = friction between plunger and pump barrel, N

W_p = weight of liquid column on the plunger, N

$W_p = H_f * D_1$ upperstroke

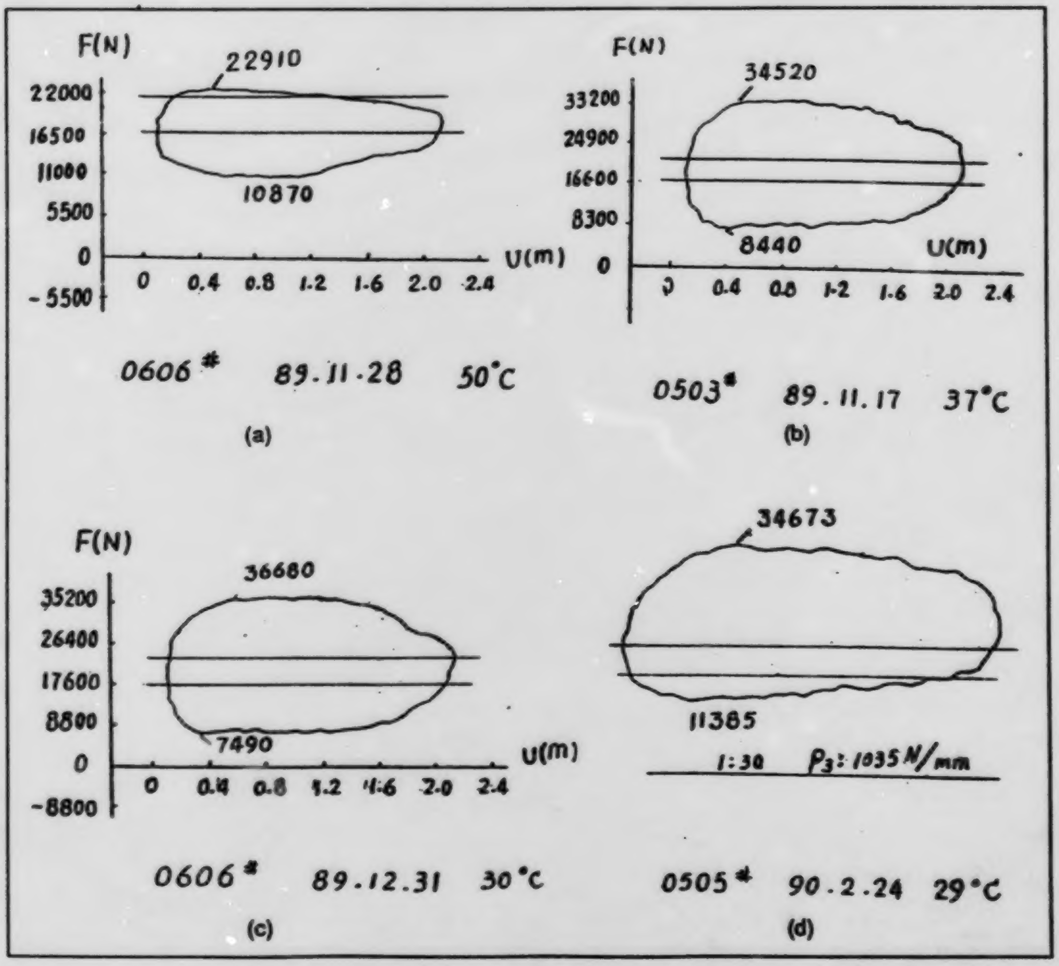
W_p = 0 downstroke

D_1 = liquid density, N/m^3

The dynamometer cards from the hydraulic recoil heavy oil pump in these slant holes are presented in Figure 13. The results indicate:

1. In the same well, the variation of oil viscosity due to temperature changes resulted in a significant difference in polished rod loads. For instance, cards A and C in Figure 13 were obtained from well 0606 at a wellhead temperature of 50°C and 30°C. The calculated corresponding oil viscosity based on these temperatures were 940 mPa and 4340 mPa respectively.

It can be found in these cards, that maximum polished rod load increased from 22,910 N (A) to 36,680 N (C), and the minimum rod load decreased from 10,870 N (A) to 7,490 N (C). Such changes are the consequence of oil viscosity increase, which escalated the friction in the downhole equipment dramatically, despite pumping operation in the said well working fine.



(a) (b) (c) (d)

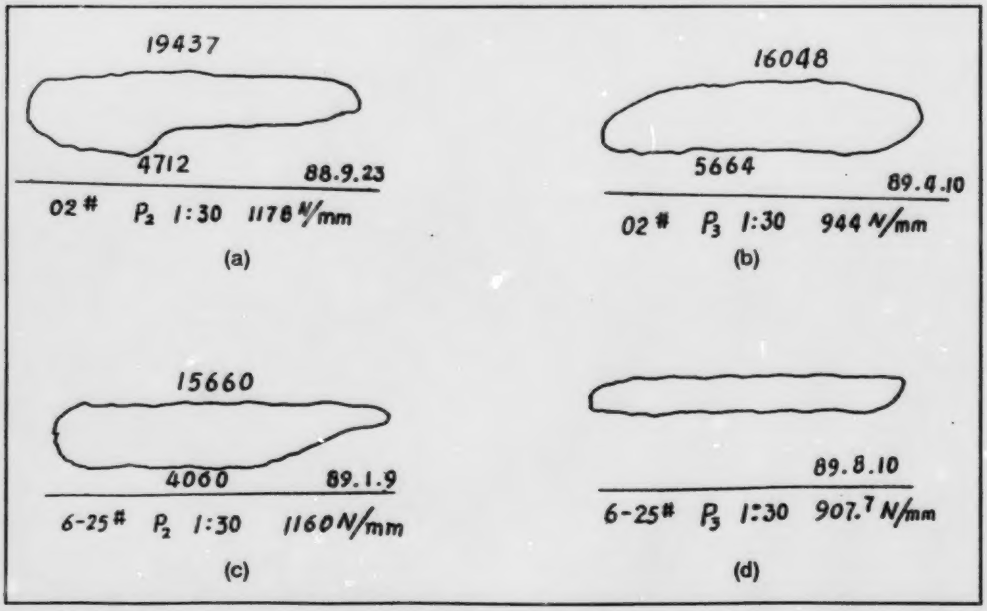
Figure 13. Dynamometer cards of the shallow directional cluster wells.

2. As far as the load condition in the vertical wells and in the slant holes is concerned, the situation in the former is better than that in the latter. This is because the sucker rods always suffer high friction and complex forces in the slat holes. Card C and D in Figure 13 represent the load recorded on well 0606 (slant hole, wellhead temperature 30°C) and on well 0505 (vertical well, wellhead temperature 29°C), respectively. The pump setting depth and other conditions are similar. From these cards, the maximum polished rod load on well 0505 was 34,673 N, which is 5.8% less than that on well 0606.

The hydraulic recoil pump developed by us has been used in 44 vertical wells. Cards in Figure 14 show the comparison of the loads obtained from the wells, which equipped the conventional heavy oil pumps or the hydraulic recoil pumps. A and C are the dynamometer cards obtained from wells with conventional heavy oil pumps, but B and D are the cards from the recoil pumps. From these cards, it is easy to see that the maximum loads are lower and the fill-up efficiencies are higher in the hydraulic recoil pumps.

CONCLUSIONS

1. Using hydraulic recoil pumps for slant holes along with conventional walking beam pumping units can meet the requirement of directional cluster wells for shallow heavy oil production, as long as sucker rods, tubing strings, and supplementing tools are reasonably designed.
2. During well completion, the irretrieved tubing string was used in the wellbore for steam injection and for pumping; this can be repeated for many cycles. Such practice not only reduced heat loss during the change from well flowing to pumping, but also extended the duration of peak daily oil rates. Economically, this practice decreased the operating costs for well service and for oil production.
3. The cycling steam stimulation to recover heavy oil



(a) (b) (c) (d)

Figure 14. *Comparisons of the dynamometer cards of the hydraulic recoil pump with the conventional pump.*

was tested in seven shallow directional cluster wells. The normal production since the beginning has been shown for nine months. However, it is difficult at present to estimate the life span of the rods and tubing service. This may be done later with practice in more wells.

4. To economically produce heavy oil under low wellhead temperatures (30°C), the pumping operation requires larger pumping units and low wellhead back pressure to ensure the proper operation in this field.

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Lifting Heavy Oil with Screw Pumps

Tim Presber

Since the late 1970's screw pumps have been tested and used in lifting heavy oils in particularly difficult environments. Continued testing has proved that in many instances, screw pumps out-perform other forms of artificial lift, not only in heavy oils but also in conventional wells. This paper is intended to suffice as a basic design document, primarily for heavy oil applications.

THE SCREW PUMP

The screw pump consists of only two primary parts:

1. a helical rotor of chrome plated steel.
2. a double helix stator of an elastomer.

The stator elastomer is bonded to the inside of a steel pipe, which is fastened to the bottom of the tubing string in the producing well. The rotor is inserted inside the stator by means of a conventional rod string from surface. The rod string and stator are suspended at the wellhead by a thrust bearing and seal assembly which permit rotary motion. The rod string is rotated at surface (usually clockwise) by a surface drive unit, either directly with a mechanical drive from an engine with a gear assembly, or indirectly through hydraulic drives.

The rotor diameter is slightly larger than the minimum inside diameter of the stator to provide for a hydraulic seal where the rotor comes in contact with the stator. As the pump is rotated, pockets of fluid are trapped between the rotor and stator and progressively moved to the top of the pump and discharged into the tubing/rod annulus.

The physical dimensions of screw pumps are not standard and for the purposes of this paper the following dimensions and definitions are adopted:

Minor diameter (d):	the smallest diameter which can be measured inside the stator
Eccentricity (e):	the distance between the axis of rotation of the rotor and the centre axis of the stator.
Pitch (p):	two complete cycles of the rotor and one complete cycle of the stator. This distance also describes the length of one pocket of pumped fluid and is also called a complete stage.

SYSTEM ADVANTAGES AND DISADVANTAGES

The screw pump is in use today because it has some distinct advantages over other systems, and in particular, rod pumping systems.

1. Fluid intake is continuous, meaning there are no pump induced variations in pump intake pressure. With volatile fluids, continuous intake can mean higher pumping efficiencies.
2. The pump will tolerate solids in the pumped fluid. Most heavy oil wells produce some quantity of sand, although it would be an exaggeration to say the screw pump is a good sand pump, it is substantially more tolerant of sand in the fluid than conventional rod pumps. There are many cases where sand cuts as high as 50% have been successfully pumped.[4]
3. There is no passive action by any part of the system. Rod pumping systems are passive on the downstroke, and when pumping high viscosity liquids, pumping speed can be restricted to the falling velocity of the rods on the downstroke.
4. Because axial loads are smaller, crooked holes can be pumped with less rod on tubing wear than wells equipped with rod pumps.[1]
5. Power demands are continuous rather than cyclic, meaning that motor capacity can be more fully utilized as compared to the cyclic demands of rod pumping systems.

6. Initial system costs are less per unit of production than for rod pumped systems.
7. Volume capacities of screw pumps are often higher than rod pumping systems.
8. In instances when power or engine failures allow sand to settle out on top of the pump, the screw pump has a better chance to be returned to service (without pulling the pump) than a rod pumping system.

However, there are also disadvantages to the screw pumping system.

1. The pump part requiring the most frequent service is the stator. Each time a pump is to be repaired, the tubing must also be tripped, increasing pump repair costs.
2. The pump requires lubrication by a liquid. If the pump is allowed to be operated lubricated by only extremely low viscosity vapour, excessive heat will cause the stator elastomer to degenerate.
3. The elastomer of the stator, using currently commercially available materials, is unsuitable for using in steam projects as the elastomers are unstable at temperatures approaching steam temperature.
4. Although the basic operation of screw pumps is simple, operating staff are often not trained in properly operating the pumps, contributing to improper installation and operations, resulting in unwarranted pump failures.
5. Head capacities are limited as compared to rod pumps. Most field use to date has been from shallow applications and pump configurations have been mass produced with low head capacities. Tests are being made of pumps with higher head capacities but they cannot yet be described as a proven technology for depths greater than 2000 meters.

SYSTEM DESIGN PROCEDURES

Pump Displacement

Theoretical pump displacement is a function of the pump geometry and the rotational speed, and is given by Gruenhagen.[2]

$$Q_{theor} = 4 \times e \times d \times p \times \text{rotational speed}$$

The formula for Q_{theor} is slightly optimistic for two reasons:

1. Because the stator is slightly deflected by the rotor, the parameter "d" overstates the size of the liquid pocket.
2. Similar to rod pumps, the pump has continuous slippage providing for lubrication of the pump.

Both these quantities together are generally assumed to be less than 5% of the overall pump displacement when the pump is operated within the rated head capacity.

The screw pumps that are commercially available are manufactured in a small number of configurations, and for each configuration, the measurements e, d, and p are unique. There are no available design calculations for a correct operating speed and so a judgement must be made based on operating experience in wells of similar conditions. In Canada, most screw pumps in heavy oil applications operate between 50 and 400 revolutions per minute. Numerous medium gravity crudes are being pumped in excess of 1000 revolutions per minute.

Suppliers of screw pumps usually have displacement charts or other guidelines which incorporate the factors e, d, and p for each pump and knowing the desired rotational speed, a pump geometry can be selected.

Calculations for pump displacement should include allowances for the volume of fluids which must pass through the pump (crude swelling due to gas in solution, elevated temperature, water, sand, and volume of free gas). If PVT data is available and provisions are made for separation of free gas prior to he pump intake, volumetric calculations of pump capacity can be fairly accurate.

Pump Head

The number of pump stages determines the head or lifting capacity of the pump. All of the pumps commercially available for commercial application seem to have about the same head capacity (about 60 to 70 psi per stage). However, the definition of a single stage varies from one supplier to the next, and when selecting a pump, make sure that stage definition is clearly understood by user and supplier.

The head requirements for a system installation are a function of the pump intake pressure and the pump discharge pressure. The pump intake pressure should be unique for any production rate and based on a reasonably reliable inflow performance relationship. The pump discharge pressure is a function of the density and height of fluid in the tubing above the pump, pressure at the tubing head on surface, and frictional losses between the pump discharge and surface.

For heavy oil applications tubing head pressures are usually taken from field observations. The frictional losses in the tubing between the pump and surface can be calculated from traditional Moody diagrams using hydraulic diameters, but, as viscosity data for the produced fluid mixture is usually not known accurately and is variable, the frictional calculations are merely rough estimates.

The pressure generated by the fluids in the tubing is a complicated calculation in heavy oil applications, especially when sand is being produced. When sand is produced, sand particles continually fall through the produced fluids (hopefully at a slower rate than the upward velocity of the fluid) adding to the proportion of sand in the tubing relative to the sand cut on surface it would not be unusual to have 10% sand inside the tubing and only 5% sand produced at surface. Knowledge of the falling velocity of sand in the produced fluid would be helpful, but again, because viscosity and phase separation information is usually variable, no accurate calculation methods for sand cut inside the tubing are available. For design purposes, it would be reasonable to assume that the sand cut in the tubing is double the sand cut on surface until some field performance data can be obtained and a relationship for sand hold-up is developed.

If any free gas becomes present inside the tubing, calculations are additionally complicated. There are some very good correlations for calculating pressure versus depth for flowing wells, but screw pumped wells have a rotating rod string inside the tubing, and the rotating rods disturb the fluid flow patterns, redistributing the flow of fluids. Until more research is available in this area, design calculations can be based on the hydraulic diameter of the tubing/rod annulus. If the produced fluids have no free gas, calculations of the effects of free gas can be ignored.

The head capacity required by the pump is then: the tubing head pressure, plus, the frictional losses from fluid flow from the pump discharge to surface, plus, the head of fluid in the tubing minus the pump intake pressure.

The total number of stages required is then the total head requirement divided by the head generated per stage of the pump under consideration. Select a pump which exceeds the number of stages required.

Surface Equipment

Two major configurations are used with screw pumps — mechanical drive and hydraulic drive.

Hydraulic drives are usually equipped with the ability to change rotational speed while the unit is running, whereas, most mechanical systems require sheave changes for rotational speed changes. Some mechanical systems are being tried with variable pitch sheaves, but widespread use has not yet occurred.

Hydraulic drive units have some inherent problems. Power conversion efficiency is much poorer than mechanical systems, and in Canada, the severe operating climate causes seals on the hydraulic motor to frequently leak. Lately, operators have been adopting the attitude that if the ability to vary the operating speed while running is not required, install a mechanical drive system.

Motors sizing is based on calculations of the lift required by the pump, the flow rate of the pump, and efficiency losses in the pump, rod string and surface drive. Historically, motors for mechanical systems have been sized with the formula:

$$HP_{Installed} > 2.0\,[1.7 \times 10^{-5}\,Q\,(P_a - P_{pi})]$$

where Q is the theoretical pump displacement (barrels per day)

P_a is the pressure above the pump (psi)

P_{pi} is the pressure at the pump intake (psi)

This equation is the hydraulic horsepower equation modified by a factor of 2.0. The 2.0 factor is intended to cover system losses. Where sand cuts are less than 1.0%, 1.5 has been found to be a sufficient design safety factor.

Motor sizing for hydraulic drive systems will be based on design safety factors in excess of 2.0 and will depend on the efficiency of the surface drive.

Rod Design

Rod strings are designed with calculations of the stresses which will be applied to the rod string. There are two forms of rod loading which create stresses: axial loads and torsional loads.

In shallow wells, the axial loads are usually fairly small when compared to torsional loads, but nevertheless, should not be ignored.

Axial load results from the net pressure applied to the net pumping area of the rotor plus the load resulting from the weight of the rods themselves. The maximum axial stress on the rod string will occur at surface, and can be calculated.

$$\sigma_a = \frac{W_{rf} + W_f}{\pi d_r^2 / 4}$$

and

$$W_{rf} = W_r (7.85 - p) L_r / 7.85$$

and

$$W_f = \left(P_a - P_{pi}\right)\left(4ed + \pi d^2 / 4\right)$$

where W_{rf} is weight of rods in fluid (pounds)

W_f is the fluid load at the pump (pounds)

d_r is the rod diameter (inches)

W_r is the weight of rods in air (pounds per foot)

L_r is the length of the rod string (feet)

p is the average density of fluids in the tubing (decimal)

P_a is the pressure above the pump (psi)

P_{pi} is the pressure at the pump intake (psi)

The torsional stresses generated at the top of the rod string is a function of:

- pump drag
- pump lift
- viscous drag of rods to fluid
- frictional drag of rods on tubing

For conventional oil applications, Presber[3] has given design calculations for rod sizing. In heavy oil applications where sand is being produced, none of these factors can be accurately calculated and also seem to be variable.[4] Practice in Canada has been to calculate the torsional stresses which might be applied to the top rod if the drive system is fully loaded. Using this design practice will ensure that the motor will stall before the rods fail in shear.

Maximum torque is then the maximum torque generated by the surface equipment and since

$$\text{Torque} = 63000 \times \text{HP}_{\text{Installed}} / \text{rotational speed}$$

If rotational speed is revolutions per minute, torque is inch- pounds.[5] Therefore, the maximum torsional stress in the rods will be:

$$T = \frac{16 \times \text{Torque}}{\pi d_r^3}$$

To calculate the maximum stress found in the top rod, Mohr's relationship is used:

$$\sigma_{max} = \sigma_a / 2 + \left(\sigma_a^2 / 4 + T^2\right)^{0.5}$$

The strength of materials is somewhat unpredictable when shearing stresses are important. A guideline which is used in conventional pumping applications is: do not exceed 60% of the yield stress of the rod material.[3]

Fortunately, only 3 rod sizes have seen extensive application for screw pumps –3/4" rods, 7/8" rods and 1" rods, and after a few pumping systems have been successfully installed, rod sizes become standardized.

RECOMMENDED PRACTICES

The following are a number of recommended practices, which are not necessarily limited to the use of screw pumps.

1. Whenever feasible, land the pump intake at the bottom of the perforations to provide for maximum free gas separation prior to the pump intake. The use of a tail pipe is redundant, and tail pipe should not be used.
2. If any volume of free gas is expected, make sure that sufficient annular space exists between the casing and the tubing/rotor assembly.
3. Ensure that sufficient space exists inside the first joint of tubing above the pump for the rotation of the rotor as the rotor is eccentric to the stator. It may be necessary to install an oversized joint of tubing immediately above the stator to provide the space required for the eccentric rotation of the rotor.
4. Use rod centralizers only when a need is clearly demonstrated through wear.[1]
5. If sufficient information exists, size the system such that the upward velocity of the pumped fluids in the tuning exceeds the falling velocity of the largest sand particles.
6. Be very careful when closing the surface tubing valve while the pump is in operation. This practice is followed by many operators to check if a rod pump is working. Closing the tubing valve on a screw pump system will cause a no-flow condition and possibly no perceivable pressure increase from a fully loaded pump. In these cases, pump slippage increases to 100% and prolonged operation will cause the stator to overheat and fail.
7. Ensure the rotor is properly spaced within the stator. If landed too high, the head capacity of the system will be reduced and the rotor will be damaged through rubbing against the inside of the tubing. Landing the rotor too low may cause the tag bar to wear out, and as this is the only real reference point for landing the rotor, subsequent spacing will be difficult. After tagging the tag bar, pick up the string weight, pull up the distance from the tag bar to the bottom of the stator elastomer, and pull up an additional distance equal to the stretch due to the anticipated fluid load, in inches:

   $$0.51 \times 10^{-5} W_l L_r / d_r^2$$

8. Ensure that the tubing string is made up to maximum torque specifications while tripping into the hole.[4] Many of the early failures were directly attributed to backed-off tubing. The rotation of the pump causes counter clockwise torque on the tubing string.

CONCLUSION

While screw pumps are a successful proven system for lifting heavy oils, much work has yet to be done for increasing the lift capacity of the pumps, increasing its temperature range for use in steam projects, and increasing overall understanding of the inputs to system design, particularly the nature of fluid flow of heavy oil mixtures containing sand, water and gas.

ACKNOWLEDGMENTS

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HEAVY OIL PRODUCTION BY BLENDING WITH LIGHTER CRUDE IN STEAM INJECTION WELLS

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ABSTRACT

Based on the studies of wellbore heat transfer, produced fluid flow, and pumping equipment performance, the conventional sucker rod pump is not effective to produce the Shanjiasi heavy and viscous crude from the steam stimulation wells. However, the existing technology can be improved by putting hot light crude in the wellbore through the sucking side of the pump to reduce oil viscosity for easier flow. The reasoning of using this new approach is discussed from theoretical and practical point of views. Also the timing for wellbore blending using hot light oil, and the details of field results are presented in this paper.

INTRODUCTION

The Shanjiasi reservoir in Shengli oil field is about 1,200 meters in depth. The dead oil viscosity at formation temperature generally varies in the range of 5,000–10,000 mPa·s. To date, more than two million tonnes of such viscous crude has been produced by cyclic steam stimulation.

During the producing cycles of steam stimulation, the oil viscosity gradually increases because of the heat loss to the surroundings, the drop of formation temperature and pressure, and solution gas coming out from oil. This viscosity increase results in the build-up of flow resistance and in the addition of substantial alternative loads to pumping equipments. Therefore some production problems such as rod string failing, electric motor buring, hanger cable breaking and rod string floating might occur. As a result, the production cycle may be terminated prematurely. These not only cost more for well service, but also affect normal field operation and decrease oil production. The mentioned problems would also happen in the early production period of steam drive projects.

The key of producing viscous crude is to improve its poor mobility. The new approach of blending such viscous oil with hot lighter crude in the wellbore could effectively improve its mobility and reduce the chance of equipments failure. Field practices and theoretical analyses indicate that this technique is practicable for viscous crude production.

THEORETICAL CALCULATION AND ANALYSIS

Viscosity of Viscous Crude, Light Crude and Their Mixture

Blending the hot lighter crude from the sucking side of the pump with the viscous crude in the producing well is based on the substantial viscosity decrease after mingling them up. The viscosity of the mixture depends on the properties of the viscous and light crude, as well as their mixing proportion.

Regression analysis on the laboratory data gives the following correlations for Shan Block 10 viscous crude, Lijun lighter crude and their mixture.

a. Viscosity-temperature correlation of the pure viscous crude

$$(1)\qquad \text{Log } u_0 = 5.5319 - 0.0377 * t \qquad t \le 60°\text{C}$$
$$\text{Log } u_0 = 4.9459 - 0.0279 * t \qquad t > 60°\text{C}$$

where u_o = viscosity of pure viscous crude, mPa·s
t = temperature, °C

b. **Viscosity of water-in-oil emulsion**

Produced liquids easily form water-in-oil emulsion in the cyclic steam stimulation wells. The correlations between the viscosity of emulsion (u_e) and the inner phase concentration (water cut by weight, o) is as following:

(2) $u_e = u_o * e^{ko}$ with $k = 4.6355$, and $0 \leq 0.415$

c. **Viscosity-temperature correlation of the lighter crude**

$$\text{Log } u_1 = 2.6022 - 0.0222 * t \quad t \leq 60°C$$
$$\text{Log } u_1 = 2.0286 - 0.0125 * t \quad t > 60°C$$

where u_1 = viscosity of lighter crude, mPa·s

d. **Viscosity of the mixture**

The viscosity of the mixture of oils (u_m) is determined by the following double-log correlation based on the viscosity of emulsion (u_e) at the given temperature, water cut and the lighter crude viscosity (u_1) at the same temperature.

$$\text{Log Log } u_m = x * \text{Lg Lg } u_1' + (1 - x) * \text{Log Log } u_e'$$

(3) $u_1' = u_1/(-3.548 - (4660/t^2) + 327.9/t + 3.081 * 10\,E{-4} * t^2)$

$u_e' = u_e/(1.029 + 2.610 * 10\,E{-5} * t^2)$

where x = dilution ratio (light crude fraction of the mixture by weight)
t = temperature, °C

Viscosity values of the viscous crude, the lighter crude, and their mixture with different dilution ratios are listed in Table 1 based on the above correlations.

It can be seen that the viscosity of Shanjiasi viscous crude (u_o) is very sensible to temperature variation. When the temperature is above 60°C, the viscosity increases by about a factor of 2 as temperature decreases by 10°C; when temperature is below 60°C, the viscosity increases by about a factor of 2.4 as temperature decreases by 10°C. Therefore, the viscosity will increase by a large margin as the temperature of produced liquid decreases during late production period of cyclic stimulation. Dilution effect is remarkable as light oil is added into the viscous crude. For example, the viscosity of the viscous crude is 4,435 mPa·s at 50°C, while the viscosity of the mixture with a mixing ratio of the lighter crude to the viscous crude being equal to 1:3 is only 556 mPa·s, which is about the value of the pure viscous crude at 80°C. The dilution effect is equivalent to pure heat effect with increasing temperature 30°C. As dilution ratio increases, the decreasing magnitude of the mixture viscosity is gradually reduced.

It should be noted that the viscosity increases several times due to the formation of water-in-oil emulsion when the produced liquid contains water. The viscosity of the viscous crude containing 20% of water is about one and a half times as much as that of pure crude. When lighter crude is blended, viscosity increasing due to the formation of water-in-oil emulsion decreases, thus, the dilution effect of lighter crude is more significant. At a given temperature, the higher dilution ratio is needed for a heavy crude with high water content in the emulsion in order to obtain the same viscosity before emulsion reverses (o < 0.415).

Table 1. Viscosity of Shan 10 Fault Block oil (mPa•s)

Temp., °C		40	50	60	70	80	90
L:V*	0:1	10566	4435	1862	984	518	272
LV*	1:4	1670	794	367	212	116	61
L:V*	1:3	1131	556	265	157	87	46
L:V*	1:2	621	321	160	99	57	31
L:V*	1:1	217	123	67	44	27	15
L:V*	1:0	52	31	19	14	11	8

Wellbore Temperature Profile Calculations

Conventional production. Wellbore temperature profile can be obtained based on the calculations of wellbore heat losses. As produced liquid flows up the wellbore, its temperature decreases gradually due to the heat loss to the surrounding formation. Taking out a wellbore interval with finite length (dl) in depth l (Figure 1), the following equation of energy balance can be obtained

$$w\,dt = k_1\,(t - t_e)\,dl \tag{5}$$

$$t_e = t_{eo} + ml \tag{6}$$

where w = water equivalent of produced liquid, W°C

t = temperature of produced liquid, °C

k_1 = overall heat transfer coefficient per meter from produced liquid to surrounding formations, wl

t_e = earth temperature, °C

t_{eo} = earth temperature at surface, °C

m = geothermal gradient, °C/l

l = depth, meters

Because of the variations of fluid properties and the differences in wellbore structure, the heat transfer coefficient k_1 and the water equivalent of produced liquid w are variables. Thus, the numerical method could be used to calculate the wellbore temperature profile in this paper. As shown in Figure 3, the whole wellbore is divided into n intervals with (n + 1) nodes. For interval number i, that is the interval $[l_1, l_{1+1}]$, from equation (5) we obtain:

$$w_{i+1/2}\left[t_{i+1} - t_i\right] = K_{1,i+1/2}\left[\frac{t_i + t_{i+1}}{2} - \frac{t_{ei} + t_{e,i+1}}{2}\right]\left(l_{i+1} - l_i\right) \tag{7}$$

The boundary condition is $l_1 = 0$; $t_1 = t_0$ at wellhead.

Therefore the temperature profile of produced liquid in wellbore can be determined. It should be pointed out that downward iterative calculations of equation (7) are liable to diverge when variable heat transfer coefficient is considered. To make the calculations converge, it is necessary to implement upward iterative calculations.

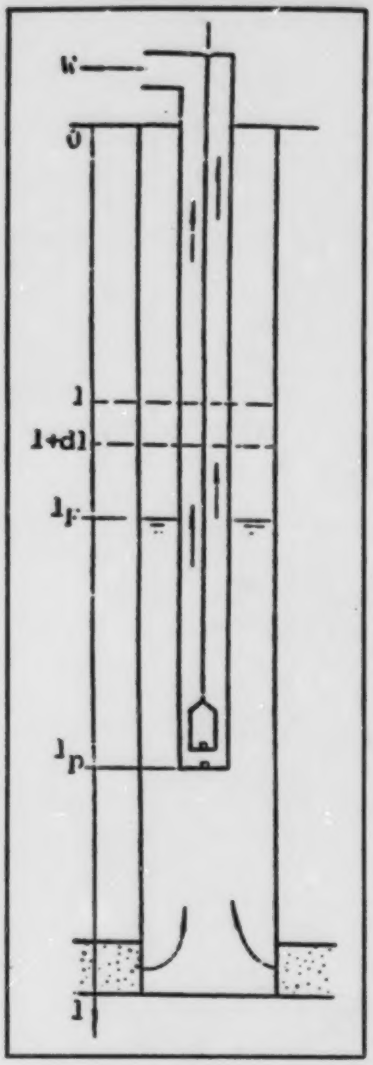

Figure 1. Schematic diagram for conventional production well.

Blending with hot lighter crude from sucking side of pump. The wellbore structure schematic diagram is shown in Figure 2. It shows viscous crude production by blending with hot light crude from the

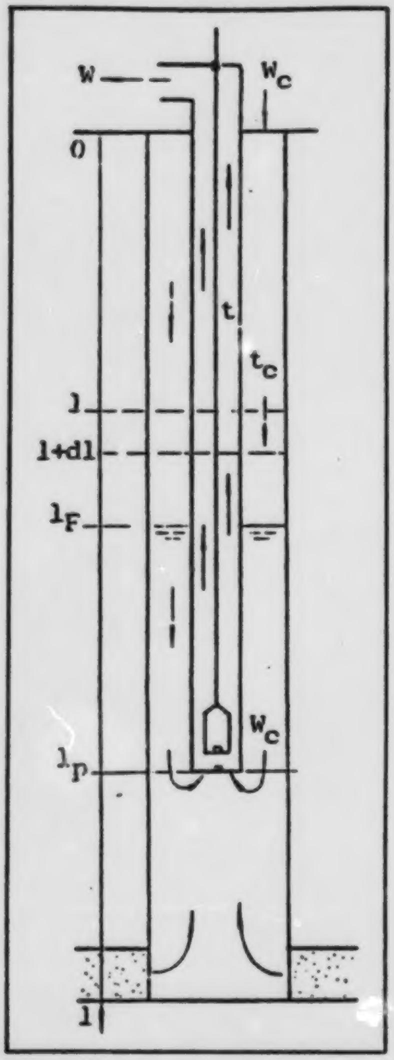

Figure 2. *Schematic diagram for production well with light oil added.*

sucking side of the pump. The heated lighter crude from the furnace is pumped into the annulus of a producing well and mixed up with the viscous crude produced from oil formations. The mixture is then pumped up to the wellhead. Based upon the physical phenomenon of blending with lighter crude, the following set of simultaneous equations of energy balance can be derived:

$$(6)\quad w\,dt = k_{11}\,(t - t_c)\,dl$$

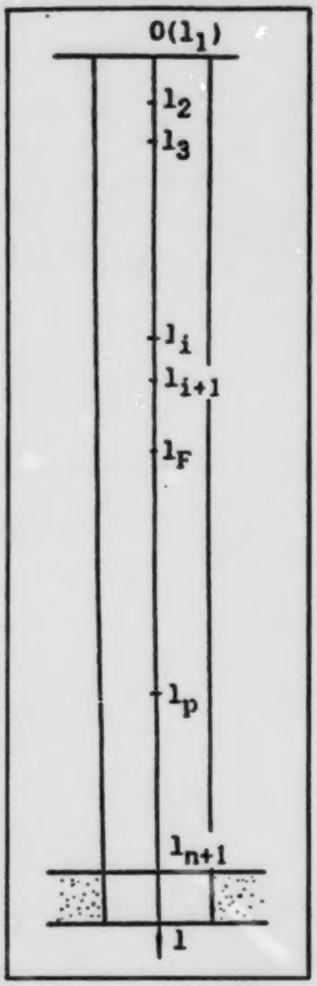

Figure 3. *Node division sketch.*

$$w_c\,dt_c = k_{11}\,(t - t_c)\,dl + k_{12}\,(t_e - t_c)\,dl$$

With the boundary conditions

at wellhead $\quad l = 0;\ t_c\,(0) = t_{c0}$

at pump depth $\quad l = l_p;\ t\,(l_p)$

$$= [(w - w_c)/w]\ t_pF + [w_c/w]\ t_c\,(l_p)$$

where w = water equivalent of the mixture, W/°C

w_c = water equivalent of lighter crude added, W/°C

k_{11} = heat transfer coefficient from the mixture to light oil, W/l – °C
k_{12} = heat transfer coefficient from lighter crude to surrounding formations, W/l – °C
t = temperature of the mixture, °C
t_c = temperature of lighter crude, °C
t_{pF} = temperature of produced liquid at pump depth before mixed up with lighter crude, °C
l_p = pump depth, meters

Ren Ying (2) gave out an analytic solution of equations (8). When variable coefficients are considered, the numerical method can be used to solve the wellbore temperature profiles. As shown in Figure 3, for interval $[l_i, l_{i+1}]$ (where $l_{i+1} \le l_p$), a set of simultaneous equations of energy balance is listed as:

$$(9) \quad W_{1+1/2}\left[t_{i+1} - t_i\right] = K_{11,i+1/2}\left[\frac{t_{i+1}+t_i}{2} - \frac{t_{c,i+1}+t_{c,i}}{2}\right]\left(l_{i+1} - l_i\right)$$

$$W_{c,i+1/2}\left[t_{c,i+1} - t_c\right] = K_{11,i+1/2}\left[\frac{t_{i+1}+t_i}{2} - \frac{t_{c,i+1}+t_{c,i}}{2}\right]\left(l_{i+1} - l_i\right)$$

$$+ K_{12,i+1/2}\left[\frac{t_{e,i+1}+t_{e,i}}{2} - \frac{t_{c,i+1}+t_{c,i}}{2}\right]\left(l_{i+1} - l_i\right)$$

The similar equations representing energy balance can also be obtained for the other intervals from the wellhead to pump depth. Therefore a five-band matrix of algebra equations is obtained. The matrix of nodal equations is solved by Gauss elimination method. The coefficient matrix is saved by a one-dimensional variable, thus only the data in the bands are saved.

Working Conditions of Pumping Equipment

During the production of viscous crude, the problem of breaking the sucker rod string often occurred in the pumping wells due to the low temperature of produced liquid. Therefore, after the wellbore temperature profile is determined, it is necessary to analyze the working conditions of the pumping equipment. That include the maximum and the minimum loads on polished rod, the maximum equivalent stress of the rod string, the critical pumping speed of the pumping unit, and the power consumption of the electric motor, etc. Also a detailed description of pressure profiles and the viscosity variations of produced liquid in the wellbore are needed.

During the pumping process of viscous crude, the multi-phase flow of water, oil, and gas in the tubing accompanied by the up and down reciprocating movement of rod string is a complicated system. Even now, this is still a problem, which has not been satisfactorily solved yet. In this paper, Orkiszewski's correlations[3] are used to calculate wellbore pressure profile for the multi-phase flow. The viscosity of live oil is estimated based on the viscosity of dead oil and the solution gas-oil ratio.[4] The methods used to calculate the critical pumping speed,[5] loads on polished rod,[6–8] rod string stress and motor power consumption[8] etc. are found in the labeled references respectively.

RESULT ANALYSIS

1. Conventional production well performance

Table 2 shows that as wellbore temperature decreases, the maximum equivalent stress on rod string increases, the critical pumping speed decreases, and operation becomes difficult. At the same wellhead temperature, the higher the oil rate or water cut, the more difficult the pumping will be. This is because at the same wellhead temperature, a higher oil production rate indicates a lower wellbore temperature profile (Figure 4) and a higher water cut indicates a higher viscosity of water-in-oil emulsion.

Based on the laboratory experiment results, when water cut increased to about 42% in the produced fluids, the water-in-oil emulsion of Shanjiasi oil started to break into two separate

*Table 2. Calculated working conditions of conventional production**

Water cut (%)	Oil prod rate (t/d)	Temp. (°C)		Max-equiv. rod stress (N/mm^2)	Critical pump-speed (m/min)	Motor power consumption (kW)
		Wellhead	Pump			
10	20	10	76	113	8	23
10	20	15	101	91	15	18
10	30	45	71	113	12	23
10	30	50	88	96	19	19
10	2n	55	87	111	12	23
10	20	60	99	97	18	19
10	30	60	81	120	15	26
10	30	65	93	105	21	21

* Rod diameter 25.1 mm
Length of stroke 3.3 m
Plunger diameter, 70 mm
Pumping speed 6 min^{-1}

phases. Thus, in the producing period with high water cut (above 42%), pumping operation will be easier due the low viscosity of the produced liquids. For example, wells Sh2-21-4, Sh2-2-1, and Sh2-39-19 can be operated normally in a conventional manner with water cut at 76%, 80%, and 78% respectively.

2. Timing for blending with hot lighter crude

In the late production of the viscous crude

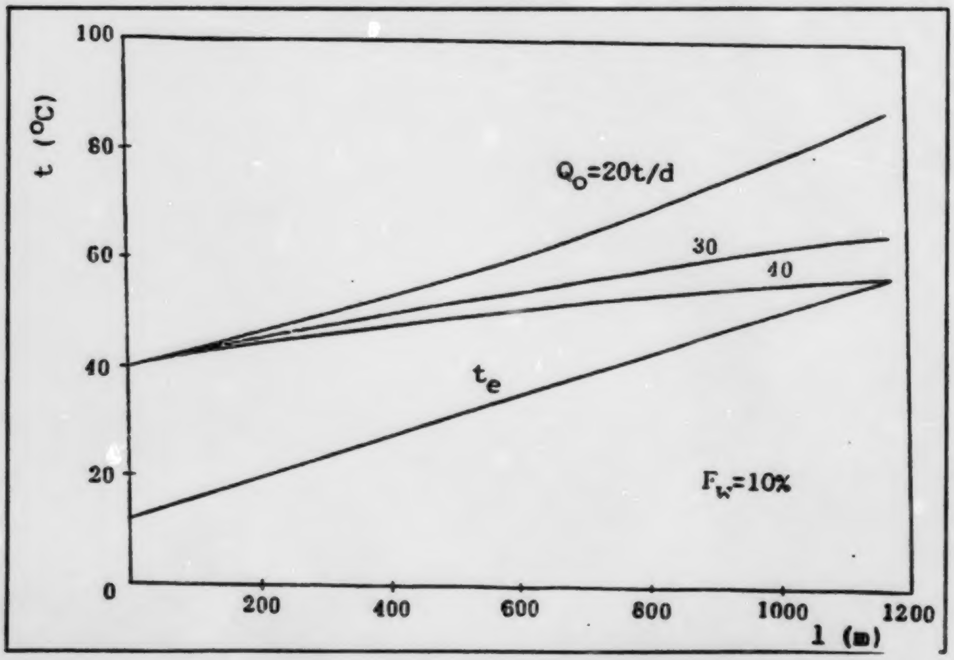

Figure 4. Variation of wellbore temperature profile with oil production rate at same wellhead temperature.

from the stimulation wells, oil rate and wellbore temperature will decrease gradually as formation temperature and pressure decline. When this reaches certain conditions, conventional production will be difficult, and the blending with hot lighter crude in the wellbore is required. If this measure is undertaken too late, the operational problems might force to shut-in the producer. On the other hand, blending too early will influence oil production and economical benefits. Hence the timing of blending with hot lighter crude is important. From the production management point of view, three parameters such as oil rate, water cut, and wellhead temperature on the producers are selected to determine the timing for blending with hot lighter crude, because:

a. These parameters are measured daily;

b. These parameters determine oil production when pumping and wellbore conditions are given.

From the above discussion on conventional practice, these three parameters have great influences on pumping operation. A comparison between calculated results and field data shows that it is practicable to determine the timing of wellbore blending by using the maximum equivalent stress of rod string and the critical pumping speed. That is, when neither is satisfied in the conventional manner of producing the viscous crude, it is the time to blend hot lighter crude in the wellbore.

Table 3. Minimum wellhead temperature of produced liquid for conventional production for Shan 10 Fault Block (c)

Oil prod. rate (t/d)		10	20	30	40
water cut (%)	10	40	45	50	55
	20	45	50	55	60
	30	50	55	60	60
	40	50	60	65	65

The timing of blending hot lighter oil in wells with Shanjiasi viscous crude is listed in Table 3, which is from theoretical calculations to show the minimum wellhead temperature required for conventional production. Accordingly, a producing well either with high oil rate or high water cut requires a higher wellhead temperature for oil production. It implies that blending operation should be undertaken earlier on those wells with the mentioned conditions. This result is consistent with the above analyses as well as the field data (Figure 5). Based upon the statistics on 72 wells in Shan Fault Block 10 after rejecting ten wells with high deviation in data, the regression equation between the wellhead temperature of producer (t_0, °C), oil rate (Q_0, tonnes/d), and water cut (F_w, %) is derived:

$$t_0 = 23.97 + 0.6359\,Q_0 + 0.9290\,F_w - 6.095 * 10\,E{-3}\,F_w^2 - 8.075 * 10\,E{-3}\,Q_0 * F_w - 5.325 * 10\,E^{-5}\,Q_0^3 \tag{10}$$

The average absolute deviation of equation (10) is 2.936°C and the average relative deviation is 5.866% as shown in Figure 6. A chart in Figure 7 showing the timing of blending was drawn based on equation.[10] For field practice, a 3°C was added for this drawing in order to compensate the said absolute deviation in the equation (10).

3. Viscous oil production after blending with hot lighter crude

Figure 8 shows typical curves of the temperature profile in producing wells before and after blending with lighter crude. To which, its temperature of about 55°C is normally obtained at the wellhead. When the temperature of lighter crude is high, such hot fluid has some heat effect on the produced liquid near the wellhead but insignificant outcome at the pump depth, even though the viscosity of the mixture (after blending) is lower than that with no light oil added. Since the viscosity of the oil mixture is not sensible to the temperature changes, the dilution by light crude thus plays a more important role to reduce the heavy oil's viscosity than that by the simple heat effect.

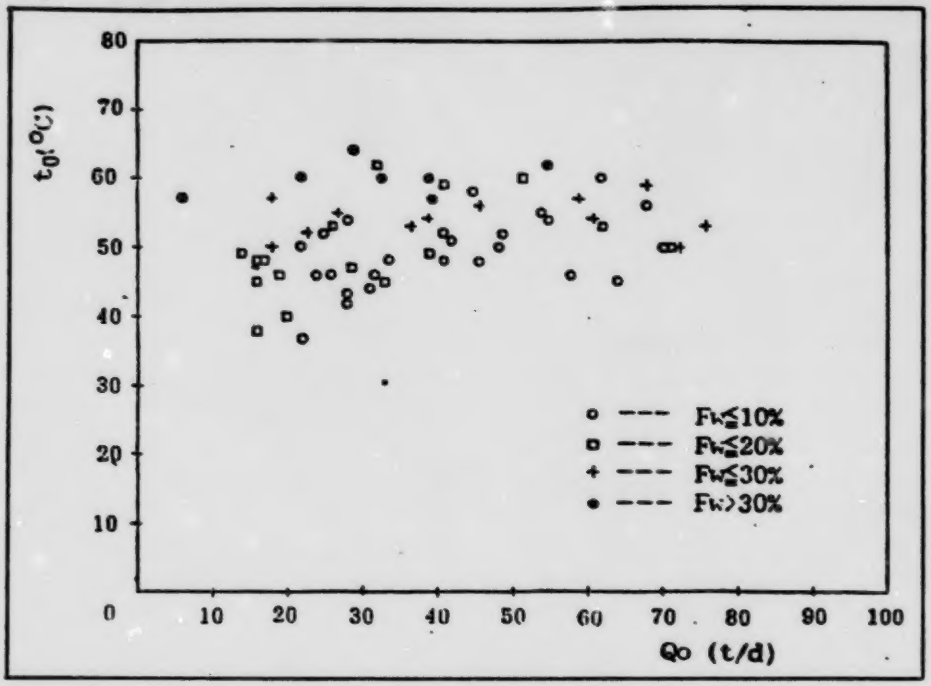

Figure 5. Statistical data of production parameters before adding light oil.

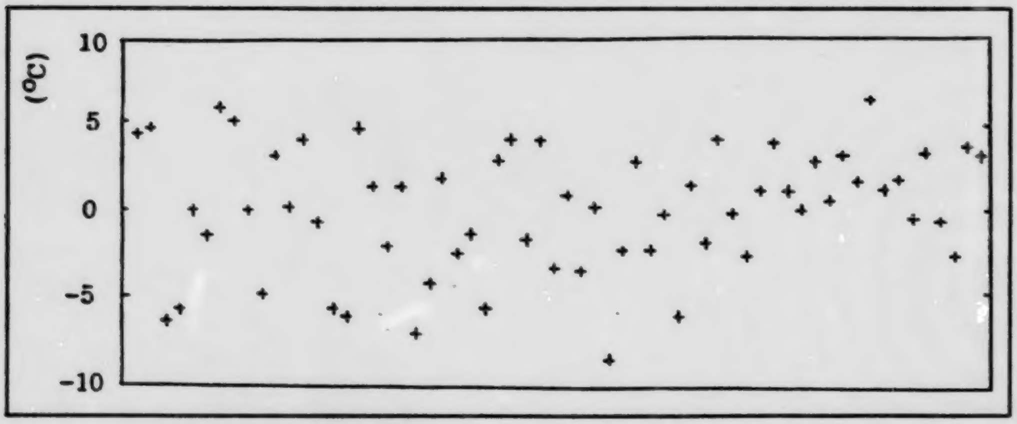

Figure 6. Regressive deviations for wellhead temperature of produced liquid.

As shown in Table 4, blending with lighter crude from the sucking conditions due to the decrease of viscosity in the produced fluid. In the given ranges, the influence of dilution ratio on pumping conditions is relatively unimportant. The result listed in Table 4 is obtained based on light crude with a temperature of 55°C at the wellhead. In practice, this temperature may vary with the amount of lighter crude added into the well. Therefore the required light crude, which is a waxy oil, should be maintained above the minimum daily supply in order to keep a normal operation in the pumping well and through the pipeline. Based on the field tests, the minimum

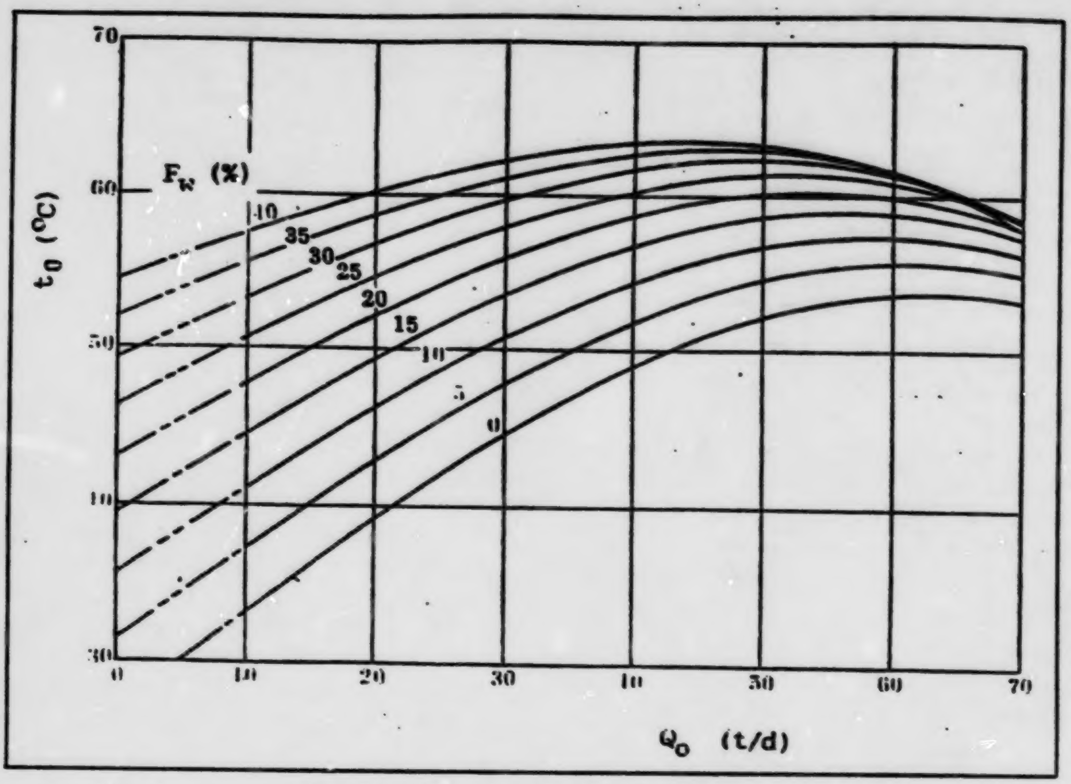

Figure 7. Opportunity chart for adding light oil.

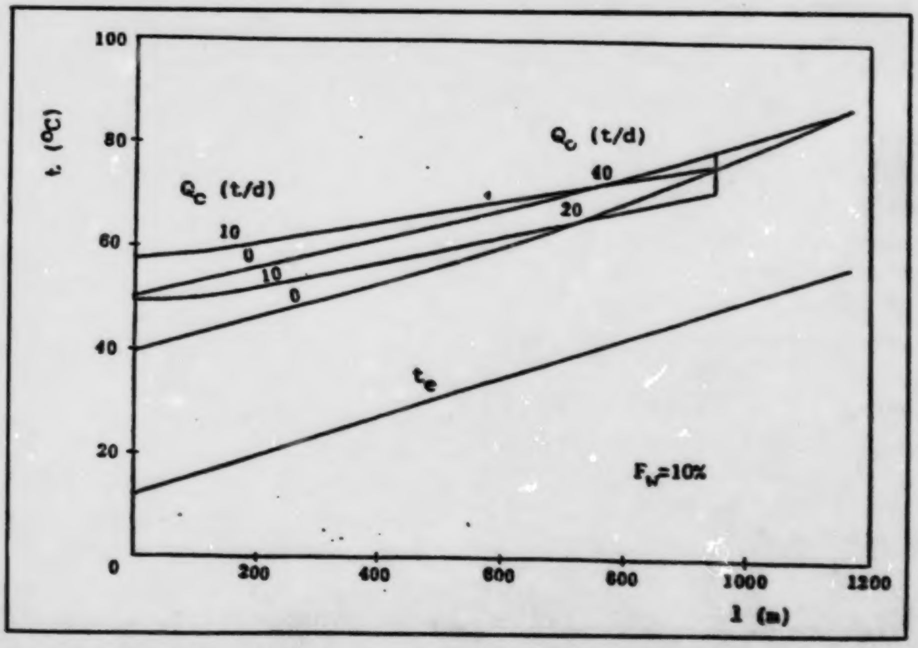

Figure 8. Temperature profiles for conventional production and adding light oil production under pump.

Table 4. Calculated working conditions of blending with lighter crude

Prod. rate (%)	Lighter crude (t/d)	Temp. (°C)		Max. equiv. rod stress (N/mm²)	Critical pumping speed (m/min)	Motor power consumption (kW)
		Wellhead	Pump			
20	7.5	44	70	83.4	58	16
20	15.0	46	70	81.4	80	16
30	7.5	47	70	85.3	51	17
30	15.0	48	70	82.4	73	16

requirement of such oil is about 8 tonnes/d to maintain normal run of lighter crude pipelines, but this should be increased in the winter. However, the sum of the maximum required light oil and the total daily fluid should not exceed the maximum lifting capacity of deep well pump. The three-year field practices indicate that the dilution ratio in the pumping wells may change with oil production rates. This ratio may be kept at a low level as oil rate is high, and vice versa. When oil production rate is more than 30 tonnes/d, the ratio of lighter crude to the viscous crude is about 1:3. If the oil rate is less than 30 tonnes/d, the ratio is about 1:2. Nevertheless, for wells producing water-in-oil emulsion (water cut less than 42%), the higher the water cut, the higher the fluid viscosity, thus, the higher dilution ratio is needed for blending in the pumping wells.

As mentioned before, the available lighter crude used for blending in this field is a waxy oil. For safety reasons to transport this oil through pipeline, the temperature must be maintained at a certain level in the pipes. In general, the wellhead temperature for lighter crude blending is usually 50–60°C.

Theoretical analysis indicates that pumping speed should be properly lowered in the late production period with low oil rate. This not only proves pumping conditions, but also reduce electric power consumption.

FIELD TEST AND PRACTICE

Testing production of Shanjiasi viscous crude began in 1984, and the field has been developed since 1985. In August 1986, blending tests with hot light crude was carried out on two wells S2-14 and S2-17. Because of good results, this test was extended to other six wells in September of the same year. The selected wells usually had some operational problems such as: high back pressure, high pumping load, and broken sucker-rod string, etc. Fortunately, these wells after the blending tests returned to normal operation and the production periods were prolonged ranging from one to four months. The results from these eight wells are presented in Table 5.

Since January 1987, the blending practice with hot lighter crude in downhole has been extensively applied in the pumping wells of the Shanjiasi field. Light crude pipeline to producers was laid, and flowmeters as well as heating equipment were installed. Figure 9 presents the complete transport network for supplying light crude in this field, and the schematic diagram for pumping wells with light crude circulation is shown in Figure 10.

Several years' field practice indicates that hot light oil blending operation to produce viscous crude in Shanjiasi field has substantially gained economic benefits. These include the aspects of prolonging production period, improving pumping conditions, maintaining normal operation on oil wells, and reducing field operating costs, etc.

Taking operation in 1988 for an example, the blending practice was carried out on 152 wells in this field. As a result, the average production period was prolonged by about 90 days per well; and the average pump repairing rate was lowered from 0.095 to 0.033 per well per month. The total savings from these improvements are detailed in Table 6.

Table 5. Production effect of blending with lighter crude of 8 Wells in Shan 2 Fault Block

Well no.	Before add lighter crude parameters		Lighter crude parameters			Viscous to lighter crude ratio	Back press. change (MPa)	Oil prod. rate change (t/d)	Motor electric current change (A)
	Water cut (%)	Prod. temp. (°C)	Temp. (°)	Press. (MPa)	Rate (t/d)				
2-14	60	steaming	78	0.3	14.7	3.2	1.4 Ø 0.8	44 ≠ 48	90/70Ø 70/55
2-17	42	steaming	74	0.2	19.2	3.0	1.4 Ø 0.8	47 ≠ 57	85/80Ø 40/60
2-19	4	58	67	0.4	20.3	3.1	0.7 Ø 0.4	80 ≠ 62	90/88Ø 70/60
2-26	8	50	62	0.3	15.1	3.3	0.6 Ø 0.5	30 ≠ 50	100/65Ø 65/40
25-9	13	55	69	0.8	16.0	2.8	0.6 Ø 0.4	38 ≠ 47	
2-25	20	54	62	0.4	12.5	2.2	1.6 Ø 0.7	25 ≠ 27	98/70Ø 75/60
2-4	30	60	70	0.6	20.4	3.0	0.5 Ø 0.4	60 ≠ 61	85/75Ø 70/50
2-16	32	40	75	0.4	21.6	1.4	0.5 Ø 0.3	6 ≠ 31	80/80Ø 50/60

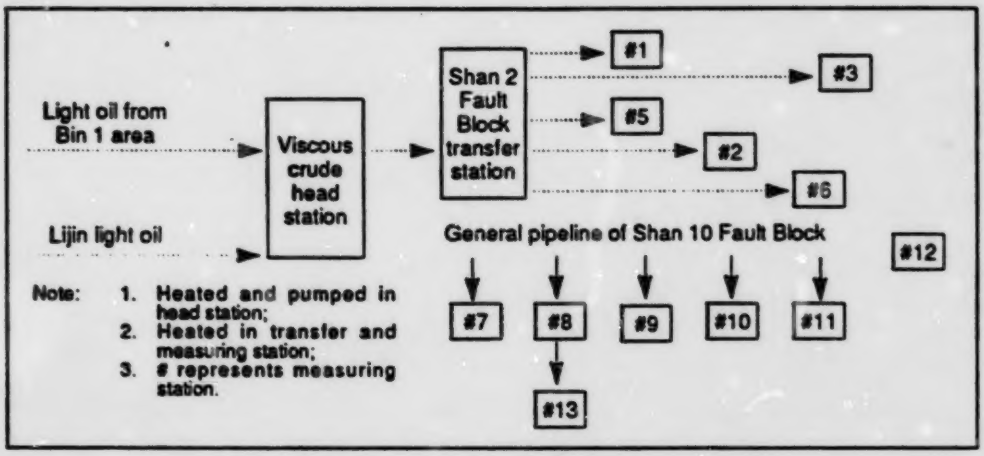
Light oil from Bin 1 area
Lijin light oil
Viscous crude head station
Shan 2 Fault Block transfer station
#1
#3
#5
#2
#6
General pipeline of Shan 10 Fault Block
#12
#7
#8
#9
#10
#11
#13
Note: 1. Heated and pumped in head station;
2. Heated in transfer and measuring station;
3. # represents measuring station.

Figure 9. Shanjiasi Oilfield network of adding light oil.

CONCLUSIONS AND SUGGESTIONS

1. During the late stages of production cycle, the oil viscosity increases due to its decreasing temperature. As a result, the resistance to oil flow escalates, normal operation cannot be maintained, and the production cycle would be terminated prematurely.
2. The mobility of Shanjiasi crude could be improved by blending with hot lighter crude from sucking side of pump. This practical approach is to maintain normal oil production, to prolong the producing cycle, and to achieve the maximum economic benefits. From theoretical and practical point of views, this technique could be applied to other viscous crude production.
3. In an analysis of this new technique, the dilution effect to reduce crude oil viscosity is more important than the heating effect on oil in the wellbore.
4. Oil properties, wellhead flowing temperature, daily oil rate and water cut are the main influencing factors to control the mobility of viscous crude in the wellbore. Field practices and theoretical analysis show that the minimum wellhead flowing temperature during conventional production depends on the daily oil

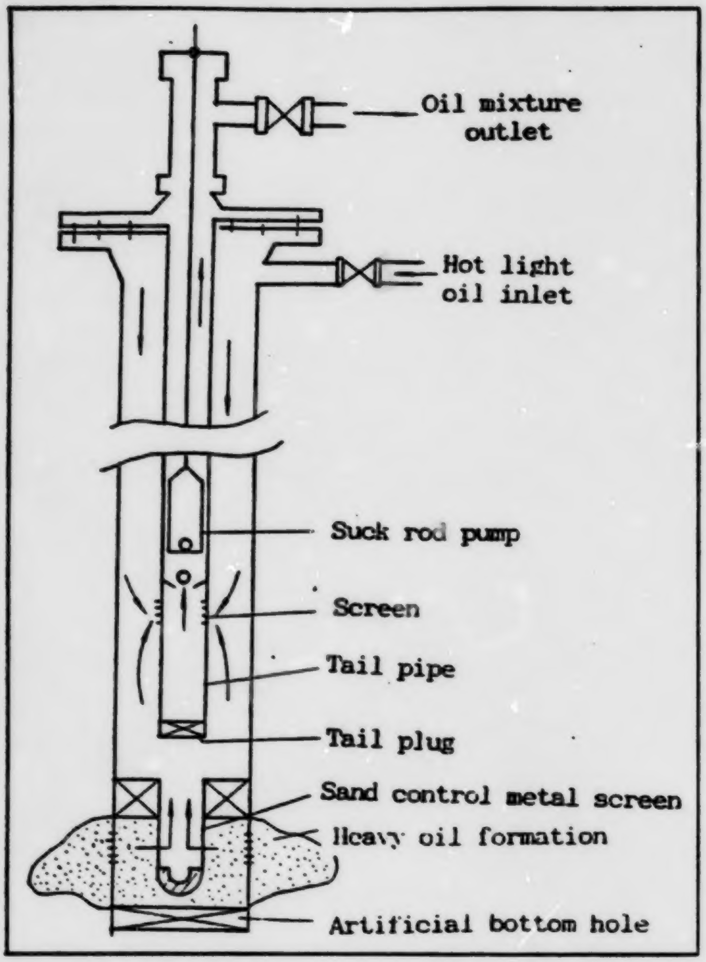

Figure 10. Schematic diagram for production well with light oil added.

rate and water cut. When the wellhead flowing temperature is lower than the minimum value, production problems may start. Thus, based on a statistical analysis of field production data, a regression equation (equation 20) was recommended being used for field practice. From this equation, the timing to initiate blending of hot lighter oil in the wellbore could be decided. In order to simplify this calculation, a chart was prepared for field use.

5. A theoretical analysis indicates that, during the early period of production form a deep reservoir under steam drive, the low temperature of produced fluids may exist in production wells. This case certainly needs the blending with hot lighter cure in the wellbore to assist oil flow. With the lapse of steaming time, viscous oil production with hot light crude added might become a routine field practice. In the future, further study of using this technique for wells produced by steam drive is technically and economically meaningful.

ACKNOWLEDGEMENT

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Table 6. Economic benefit of blending with lighter crude in Shanjiasi (calculated based on 152 wells in 1989)

Comparisons of the two production techniques		Converted number of wells per year	Reduced number due to adding lighter crude per year	Average cost ten thousand yuans	Saved cost ten thousand yuans
Avg. cycle prod. time for for 1988–89 based on Shan 10 Fault Block well (days)		cyclic stimulation operation			
Before adding lighter crude (128 wells)	110.8 + 30*	394.0	155.2	8.0	1241.6
Whole cycle (105 wells)	202.3 + 30*	238.8			
Production fault rate (per well per month)		production fault treatment			
Without adding lighter crude	0.0940**	1714.56	1158.24	0.03	34.75
Blending with lighter crude	0.0305***	556.32			
Pump repairing (per well per month)		pump repairing operation			
Without adding lighter crude	0.095**	173.28	123.09	2.0	246.18
Blending with lighter crude	0.033***	60.19			
steam injection (based upon the steam cost of 18.19 yuans per ton and the average cyclic steam injection amount of 4000 tons in 1989)					
lighter crude pumping and heating (based upon the average cost of 1.5 yuans per ton and the average amount of 1000 tons in 1989)					–54.75
net economic benefit per year					2597.01

7. Wang, H.X., "Problems on conventional techniques in pumping viscous oil," (in Chinese), Oil Drill. and Prod. Tech., vol. 7, no. 1, 1985.

8. Wang, H.X. and Zhang, Q., "Principals of oil well production technology," (in Chinese), Petr. Industry Press., Beijing, Dec. 1981.

SAND-FILLED CHANNELS: A NOVEL FIELD STRATEGY FOR ENHANCEMENT OF THERMAL RECOVERY OF HEAVY OIL

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ABSTRACT

Recent progress in directional drilling and completion technology[1,2,3,4,5] opens new possibilities for economic recovery of large heavy and extra-heavy oil deposits. Horizontal wells used for both injecting hot fluids and collecting produced oil emulsions can extend up to 1500 m from the injection point into the heavy oil reservoir to improve the effectiveness of thermal recovery and to ensure the efficient distribution of hot fluids in a stratified heavy oil reservoir, a new horizontal drilling and completion strategy eliminating the use of conventional slotted liners was proposed. This paper discusses the new process which uses a network of horizontal/deviated boreholes uniformly filled with sand of a predetermined permeability. In combination with HAS-pipe[6,7] (heated annulus steam drive) process, or by itself, the sand-filled channel strategy can significantly contribute to increasing the initial rate of oil production. The suggested strategy can be designed to combine in a optimal manner the hot fluid drive and gravity recovery mechanisms.[8]

The key characteristics of the system and simplified design criteria for sand-filled channels discussed in the paper include permeability, cross-section, and lateral extension, and were analyzed in terms of functional criteria such as plugging avoidance and oil/steam ratio. The sensitivity study presented in the paper uses both physical simulation at a laboratory scale and numerical/simulation of simplified field-scale recovery processes. It is shown that optimal design characteristics strongly depend on the viscosity of oil at reservoir temperature and on the formation permeability.

INTRODUCTION

Alberta Heavy Oil

Four large deposits of oil sands are located in the northern half of Alberta: Athabasca, Cold Lake, Peace River, and Wabasca; they cover an area larger than 7 million hectares. The Alberta Energy Resources Conservation Board estimates that these deposits contain approximately 215 billion cubic metres of bitumen. Of this amount, only 8 billion cubic metes are recoverable by conventional mining techniques from near-surface deposits; the remaining deposits are too deep to be economically mined. New in situ recovery techniques aimed at producing bitumen from deeper formations, at marketable prices, are under development.

At normal reservoir temperature, bitumen is totally immobile. Mobilization of bitumen through the application of heat requires efficient transfer of heat injected into the formation. This involves a good distribution of heating sources and a large contact area between hot fluids and the reservoir. A number of approaches have been taken to improve heat penetration and bitumen recovery, including steam stimulation, team drive gravity drainage, and combustion drive. The technologies which have been successfully implemented on a commercial scale in Alberta are steam stimulation in the Cold Lake and Lindbergh areas and pressure cycle steam drive in the Peace River area. Some Cold Lake reservoirs respond well to cyclic steam stimulation and substantial production is being achieved at Esso's operation.

Steam stimulation or huff-n-puff[9] is a one-well process. It involves the injection of steam into a well and then producing the well after allowing the heat to dissipate and oil to drain for some time.

Microfracturing of formation, gravity drainage, and natural interwell communications, each contribute to high recovery. The cycle is repeated until operating costs exceed the value of the produced oil. Therefore high well densities, especially for low-viscosity and low permeability formations are required. Total recovery is reported to be of the order of 15–20% of the oil in place. The relatively high viscosity of the bitumen in the Athabasca deposit and the lack of formation energy, combined with the most complete geology of all the deposits, have so far resulted in limited success at the field pilot stage. To improve the recovery from each vertical well to approximately 25%, the interwell distance was reduced from approximately 60 to 45 m (Texaco-Athabasca). That is why, of the initial capital cost of a semi-commercial field operation, 50–60% is for drilling the initial wells, 15–20% is for steam generation, 15–20% is for treating produced water, and the remaining 10–15% is for bitumen treating and off-site costs.

The recent development of directional drilling such s the use of downhole drilling motors and MWD (measurement while drilling) as well as the development of the water-jet piercing technology open new avenues to the in situ recovery of heavy oil. Horizontal wells reaching as far as 1500 m are improving the reservoir contact with injected hot fluids compared to vertical wells. Also the price of drilling, cementation, and completion per each metre of well in contact with the pay zone is reduced three to ten times as compared to conventional, vertical wells. Recent observations made in the Athabasca deposit using pairs of horizontal wells (UTF) have indicated surprisingly high oil recoveries for gravity drainage. Gravity drainage using paired of horizontal wells and good enthalpy control operating from underground tunnels (AOSTRA-UTF, SAGD process) is an important achievement and demonstrates the effectiveness of the gravity drainage and the steam chamber rise concept assisted during the initial stages by interwell steam drive. Yet, improving and controlling the distribution of steam in long horizontal wells, enhancing the initial heating stage, and optimally controlling the gravity process are in the research stage. A gravity process assisted by hot fluid drive was suggested[11,12] to enhance the gravity drainage from long horizontal wells, and to improve the ability to control the reservoir fluids and steam distribution. This paper presents the results of laboratory and numerical studies of a novel method for the enhancement of gravity drainage using an induced axial drive recovery mechanism.

Hot Fluid Communication

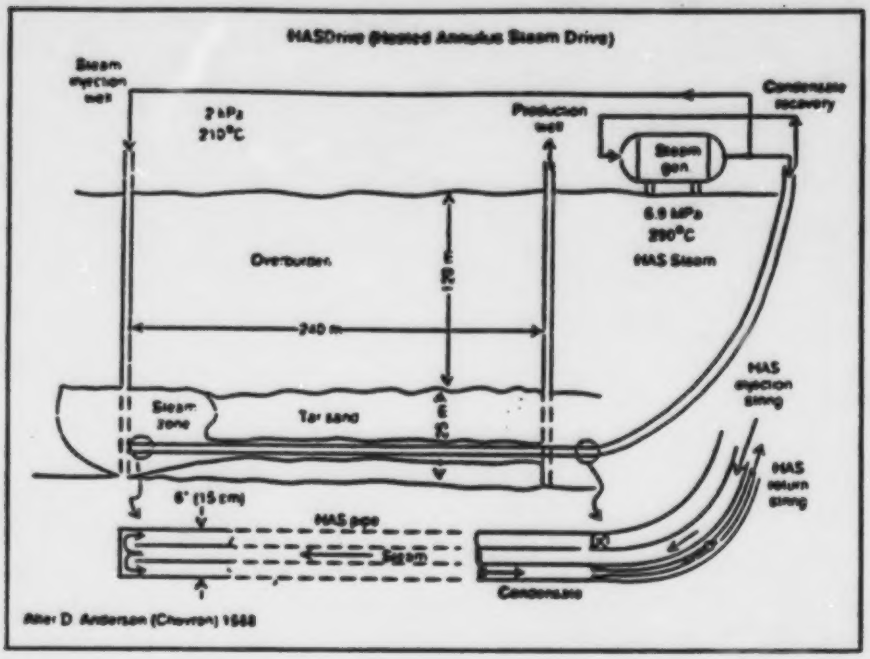
Controlling the hot fluid communication is an essential condition to produce extra-heavy reservoirs such as Athabasca.[13]

Aiming to offer better reservoir control and less expensive completion, two new gravity assisted recovery concepts, the Heated Annulus Steam Drive (HASDrive) 714 and Sand-Filled Multiple Channels (SFMC), have been recently proposed. Both the HASDrive and the SFMC are using horizontal well drilling technology to contact large reservoir zones.

In the HASDrive, steam is initially injected in a horizontal line (HAS-pipe), return string being used for condensate return (Figure 1). After the oil sand formation adjacent to the HAS-pipe has been preheated, injection of steam in the pipe is replaced by steam injection in the annular preheated oil sand which starts the recovery process.

The SFMC utilizes an array of horizontal or deviated boreholes connecting injection and production wells (Figure 2). The channels are packed with sand of predetermined size.

Two mechanisms contribute to the recovery processes for both SFMC and HASDrive: axially induced steam drive and gravity drainage. To assess the key parameters controlling the steam drive mechanism with sand-filled channels or HASDrive, a laboratory program was initialed.


HASDrive (Heated Annulus Steam Drive)
Steam injection well
2 kPa
210°C
Production well
Condensate recovery
Steam gen
6.9 MPa
290°C
HAS Steam
Overburden
240 m
Steam zone
Tar sand
HAS injection string
HAS return string
6" (15 cm)
HAS pipe
Steam
Condensate

After D. Anderson (Chevron) 1988

Figure 1. Schematic of the HASDrive process.[7]

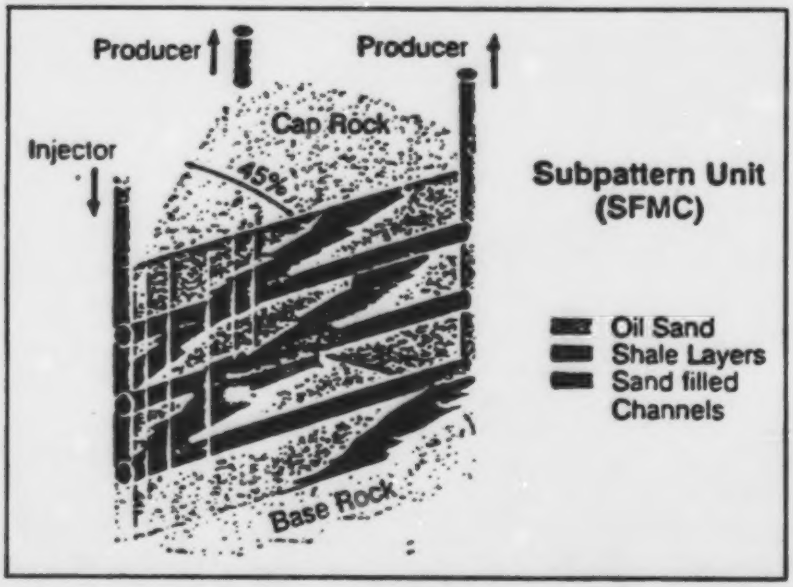

Producer
Producer
Injector
Cap Rock
45%
Base Rock
Subpattern Unit
(SFMC)
Oil Sand
Shale Layers
Sand filled
Channels

Figure 2. Schematic of the sand-filled multilevel channel (SFMC) process in a layered heavy oil formation.

A numerical model which was first calibrated using simulated laboratory experiments was used to investigate simplified field-scale situations and for a screening study.

LABORATORY INVESTIGATIONS

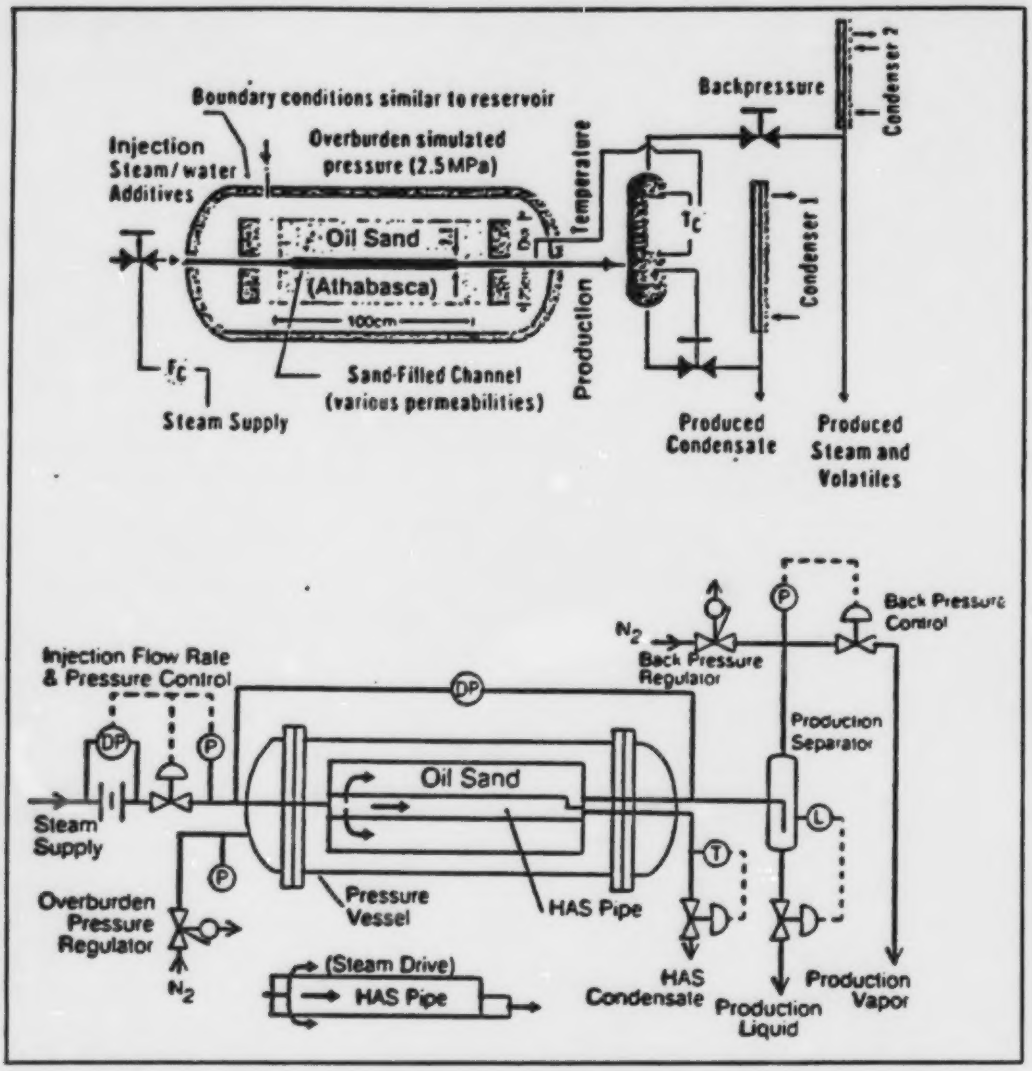
Equipment

Laboratory simulation involves two steam drive experiments performed to compare the SFMC and the HASDrive processes and 50 experiments for assessing the hot fluid drive with SFMC. A physical simulator for horizontal wells[15] was used for this study. A cylindrical lead-sleeved pack 1 m in length and 0.25 m in diameter containing approximately 95 kg of surface-mined tar sand, was pressurized at 3.5 MPa to simulate 150 m of overburden. The pack used for the SFMC simulation was provided with an axial 3.8-cm diameter (1 1/2") cylindrical sand-filled channel of approximately 5 mm^2 permeability; for the HASDrive simulation a HAS-pipe of the same diameter, perforated near the injection side, replaced the and channel. Consistent packing procedure creating a bulk density of approximately 1.95 g/cm^3 was employed for all experiments.

Figure 3 schematically presents the main parts of the experimental rig and the pack used for laboratory investigation.

Constant-Injection Experiments – Recovery

The effect of pressure drop on recovery for SFMC


Boundary conditions similar to reservoir
Injection Steam/water Additives
Overburden simulated pressure (2.5 MPa)
Oil Sand
(Athabasca)
100cm
Sand-Filled Channel (various permeabilities)
Steam Supply
Temperature
Production
Backpressure
Condenser 2
Condenser 1
Produced Condensate
Produced Steam and Volatiles
Injection Flow Rate & Pressure Control
DP
P
Steam Supply
Overburden Pressure Regulator
N_2
Oil Sand
Pressure Vessel
HAS Pipe
(Steam Drive)
HAS Pipe
N_2
Back Pressure Regulator
Back Pressure Control
Production Separator
L
T
HAS Condensate
Production Liquid
Production Vapor

(a)
Sand-filled channel configuration

(b)
HASDrive configuration

Figure 3. Schematic of the experimental rig.

was investigated using data from approximately 50 experiments performed in the 1-m cell. A constant injection rate and 200°C temperature was used throughout this group of tests. The quality of injected steam was varied from 0% (hot water) to 100%, and the permeability of the bypass zone was varied between 5 to 200 mm². An injected heat rate of approximately 8.5 MJ/h was maintained by adjusting the injection flow rates for each run.

During a constant-rate injection, measured pressure drop above the sand channel was variable (Figure 4).

It was found that the smoothed value of pressure drop Dp^{15} measured when recovery reaches 15% is best correlated with final recovery values. Final recovery (R) was evaluated al the time the cumulative oil/steam ratio (OSR) reaches 1/3 of its maximum:

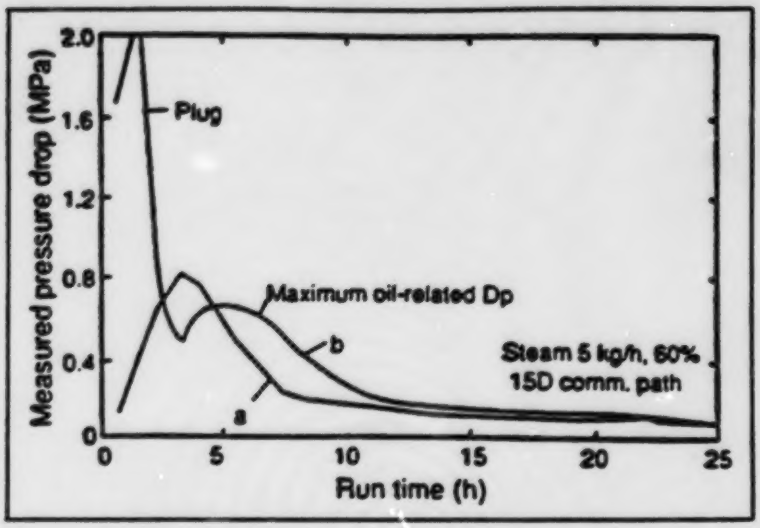


Figure 4. Typical pressure drop variation during a SFMC-constant injection.

$$(1) \quad R = 69 - \frac{3491}{Dp^{15}} \text{ (\% OOIP)}$$

where Dp^{15} is in kPa.

Equation 1 indicates that, in the absence of gravity drainage for an extremely high pressure drop, maximum obtainable recovery would be 69% also, for a pressure drop lower than 50 kPa (see B/A Equation 1) the fluid drive recovery of Athabasca bitumen cannot be initiated (fluid at 200°C).

Critical Flow and Plugging

For some (steam) experiments (Figure 4, profile b) an early maximum of the pressure drop, preceding the oil related maximum value, was detected which indicated an initial plugging tendency[10] of the sand channel.

To avoid the occurrence of an initial plugging situation, only hot water (200°C) is injected during the first 2 h of the SFMC experiment using sand with permeabilities under 20 μm².

Oil Steam Ratio

Field, laboratory, and computer simulated studies for extra-heavy oil recovery controlled by bypass hot fluid flow indicate bell-shape curves for oil/steam ratio (OSR) and total oil production.

Figure 5a presents a typical production rate curve obtained in the field[16] (Kern River) and cumulative OSR during hot water and steam laboratory experiments.

Figure 5b indicates key features of the OSR curve used for process comparisons and economics which are: maximum OSR (M_o) time to maximum OSR (T_o) time to first oil production (T_{oo}), and total time spent at OSR > 0.73 (M_o) or "Span."

A simplified model was selected for comparison of laboratory and field data.

$$(2) \quad Y = X^B e^B (1 - X)$$

where the dimensionless time is:

$$X = \frac{t - T_{oo}}{t_o - T_{oo}} \qquad Y = \frac{(OST)_t}{M_o}$$

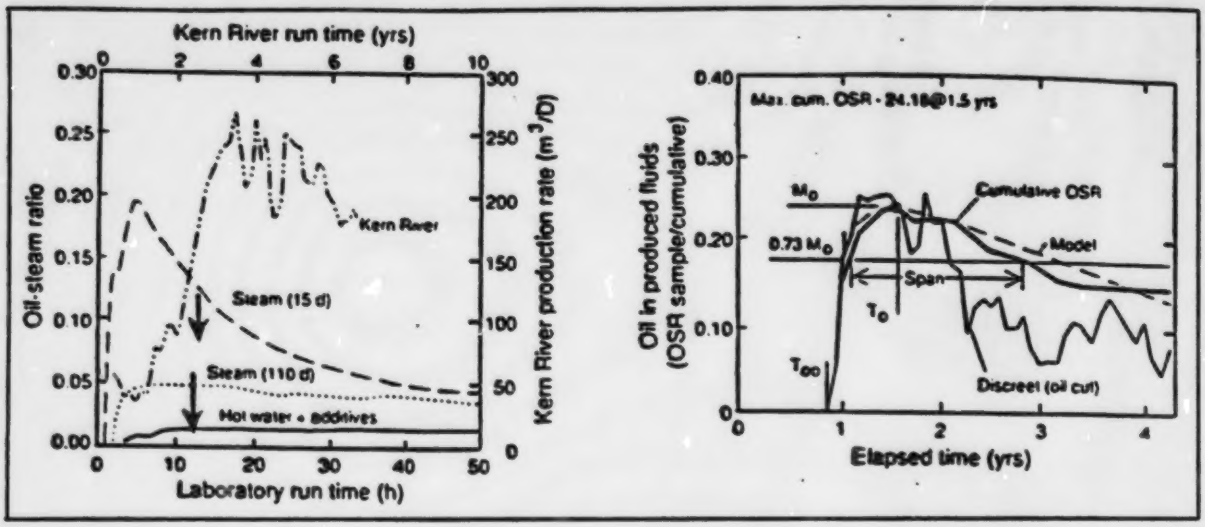
B is a coefficient (shape factor) determined using statistical regression of experimental/field data or, from the measured Span value such as:

$$(3) \quad B = 2.5972 \left(\frac{\text{Spantime}}{T_o - T_{oo}} \right)^{-1.954}$$

Table 1 presents the coefficients of the OSR model for field data and for simulated steam drive and hot water sand channels experiments (1-m cell).

HASDrive and SFMC

In order to closely reproduce the SFMC pressure drop regime, the back pressure was adjusted twice during the HASDrive experiment, i.e. until 2 h of elapsed run time, approximately 300 kPa was maintained; after 2 h, the controlled pressure drop value was increased to 600 kPa (see Table 2). Results



(a) (b)

Figure 5. OSR and production rate for field pilot, laboratory simulated hot water, and steam drive laboratory experiments (a), essential characteristics of the OSR curve (b).

of laboratory experiments indicated differences between the development of temperature profiles during the SFMC and HASDrive processes can be seen in Figure 6, an override tendency is visible in the first half of the pack of the SFMC; the distribution of temperature is more uniform around the HAS-pipe than around the sand channel. Considerably higher temperature regimes in the front half of the pack as compared to the rear half are observed in the SFMC whereas the differences observed in the HASDrive are much smaller (Figures 7a, b).

The development of "concentrated" recovery zones specific to the SFMC process and of "uniformly distributed" recovery specific to HASDrive, are schematically illustrated by the comparison of temperature development in Figure 6b.

Temperature and heat balance data are further used to determine the rate of heat transfer from the HAS-pipe to the tar sand:

$$\left(CM\frac{\Delta T_b}{\Delta t} + A_o U_o\left(T_b - T_o\right)\right) / \left(A_s\left(T_s - T_b\right)\right) \qquad (4)$$

where A_s and A_o are the HAS-pipe/SFMC tar sand contact area and outside pack areas respectively;

T_b, T_s, T_o are the tar sand, steam and surrounding temperatures continuously monitored; and

U_o is the heat transfer coefficient to surroundings, measured during cool-down to be approximately 90 kJ/m^{2}h°C.

Laboratory data indicate that the overall heat conduction load was 440–490 kJ/m^{2}h°C (122–136 W/m^2°Cp) for the HASDrive due to convective enhancement and rapid expansion of the convection-conduction interface, the overall load measured for the SFMC process was twice as high and indicates larger variations.

Figure 8 compares recovery of SFMC and HASDrive, and indicates a nigher rate of recovery for SFMC than for HASDrive, in spite of lower bull temperature observed during the first 6 h of the SFMC run.

Table 1. Essential characteristics of the cumulative OSR from laboraotry and field data and model coefficient "B"

	Experimental value					Shape factor calculated (B)			
							Model 1B		
#	Steam quality	Bypass perm (μm²)	Time to 1st oil T_{oo} (min)	Time at max OSR t_o (min)	Span at 73% max OSR (min)	Direct B**	Correl'n r^2	Std. error	Indirect B**
1	1	200	90	486	917	0.6305	0.8367	0.1106	0.516
2	1	100	60	250	400	0.2291	0.8676	0.0905	0.619
3	1	100	70	400	625	0.2859	0.8148	0.0996	0.759
4*	0.8	100	226	850	2800	0.1773	0.8790	0.0906	0.144
5*	0.8	100	200	650	2850	0.0806	0.8266	0.1046	0.074
6	0.8	100	110	500	2450	0.0916	0.9210	0.0524	0.075
7*	0.8	100	140	550	2800	0.0884	0.6580	0.1120	0.064
8*	0.8	100	142	500	1150	0.1813	0.7832	0.1057	0.275
9*	0.8	15	150	550	825	0.3393	0.8946	0.0831	0.644
10	0.6	15	80	450	825	0.3092	0.9199	0.0672	0.555
11*	0.6	15	88	300	475	0.2299	0.8655	0.0896	0.549
12*	0.6	15	70	350	525	0.3717	0.8559	0.0916	0.774
13*	0.6	7	130	450	550	0.3966	0.7296	0.1312	0.915
14*	0.6	7	80	350	400	0.4106	0.8083	0.1052	1.219
	Field	Max. rate (BOPD)	Time at max rate M_o						
	1A	287	4.0			0.3410	0.1273		
	2	1676	18			1.8416	0.7528		
	3	278	9.4			5.643	0.9115		
	4A	1930	22.5			0.4222	0.5264		
	4B	2200	72.5			3.0836	0.8689		

* preconditioning/commingled additive strategy employed
1A Inglewood
2 Kern River 10-pattern
3 Smakover
4A PADS J-sand (Shell-North Midway Sunset/Kern River)
4B PADS J-sand (Shell-North Midway Sunset/Kern River)

Figure 9 compares the cumulative OSR. A maximum OSR of 0.148 was reached after 480 min in the HASDrive experiment. The SFMC reached 0.125 in 405 min. If the condensate produced in the HAS-pipe is not included in the calculated value of OSR, approximately 0.5 (50%) is reached at maximum. This is an extremely high yield for any laboratory simulation of a steam drive recovery process. It appears, however, from the detail of Figure 9, that the first occurrence of the HASDrive production is delayed by 50 min as compared to SFMC, in spite of the first 2 h of hot-water-only injection only used to initialize the SFMC and avoid initial plugging.

This observation is consistent with previous laboratory observations indicating the requirement of a minimum threshold pressure drop to trigger the production of oil in a hot-fluid drive process.

NUMERICAL SIMULATION STUDY

A multicomponent thermal compositional model has been developed at the Alberta Research Council.[17] It is a fully implicit simulator capable of handling three components in addition to heavy oil

Table 2. Experimental conditions – SFMC-HASDrive laboratory comparison

	Units	SFMC	HASDrive
Tar sand pack (surface mined – Athabasca)			
• weight	kg	91.4	94.4
• length	cm	98.5	100
• diameter	cm	25	25
• bulk density	g/cc	1.94	1.97
• oil sat.	wt%	14.8	13.7
• water sat.	wt%	1.5	1.95
Sand-filled channels/HAS-pipe			
• diameter	cm	3.8	3.8
• sand permeability	μm^2	–	approx. 0.5
Overburden pressure	MPa	3.5	3.5
Injection			
• strategy		adjusted Dp	constant Dp
• initialization		200°C hot water for 2h	200 kPa DP for 2 h
• fluid		steam 80%	steam 80%
• temperature	°C	200	200
• pressure	MPa	1.55	1.55
• flowrate	kg/h	5	max. 5
• pressure drop	kPa	max. 420	2 h ... 300; 2–40 h 420
Run time	h	38	30
Cool down test	–	yes	yes

and water. Conservation equations for energy and the mass of all five components are solved.

The model uses analytical correlations and derivatives only. Mass transport is governed by Darcy's law.

The equations represent an extension of equations recommended by Coates,[18] which allows for solubility of all components except the heavy oil in all phases. The heavy oil is limited to the oil phase, which according to Peng-Robinson's[19] equation of state, does not restrict the accuracy of the model.

Prior to field-scale modeling of the SFMC process, the numerical technique and essential parameters employed by the model were validated using laboratory data.

Table 3 summarizes essential rock and fluid properties employed during the sensitivity study of the SFMC process.

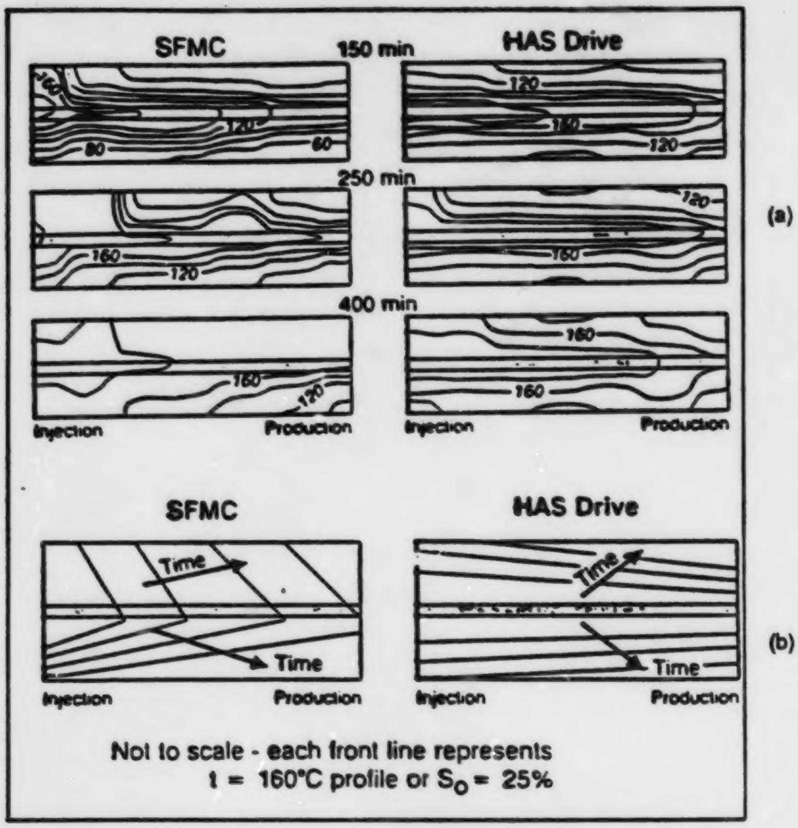
SIMPLIFIED FIELD MODEL (SFMC)

Figure 10 indicates the various grid geometries employed for the computer model. To simplify the model and save computer time, the typical triangular shape, featuring one-eighth of a five-spot pattern, which is frequently used for simulation of steam flood-frontal displacement processes (Gomaa, 1980), was replaced with a rectangular geometry of 20 m x 20 m x 40 m, frequently used for simulating a horizontal channel (Hsueh, 1986; Jain and Khosly, 1985).

The baseline case used for the SFMC method considers one channel of 0.45 m 0.45 m situated 6 mm from the base rock (bottom level) and filled with 25 μm^2 sand.

Constant Injection Strategy (SFMC)

Figures 10 shows recovery and OSR versus total


SFMC
150 min
HAS Drive
160
120
80
60
120
160
120
250 min
120
160
120
160
400 min
160
120
160
160
Injection
Production
Injection
Production
(a)
SFMC
HAS Drive
Time
Time
Time
Time
Injection
Production
Injection
Production
(b)

Not to scale - each front line represents $t = 160°C$ profile or $S_o = 25\%$

Figure 6. Development of temperature profile in the tar sand pack: (a) SFMC and HASDrive – 1 m cell and (b) schematic of development.

pressure drop at 15% oil recovery from a single bottom-level channel (0.45 m x 0.45 m) for 0.8 μm². Data from four computer simulations using channel permeabilities of 100, 200, 400, and 800 μm² are indicated. Approximately 10 tonnes/d of steam injected al 200°C and 70% saturation were used.

A hyperbolic relationship between recovery and pressure drop (Figure 10a and Equation 5), and between maximum OSR and pressure drop (Figure 10b and Equation 6) for each simulated run was found to correlate the best.

The statistical correlations use:

$$\text{(5)} \quad \text{Recovery} = 55.28 - \frac{18800}{D_p(15\%)}$$

D_p^{15} is the pressure drop between injection and production, recorded at the moment recovery reaches 15% of the original oil in place (OOIP). Equations (5) and (6) indicate a maximum achievable

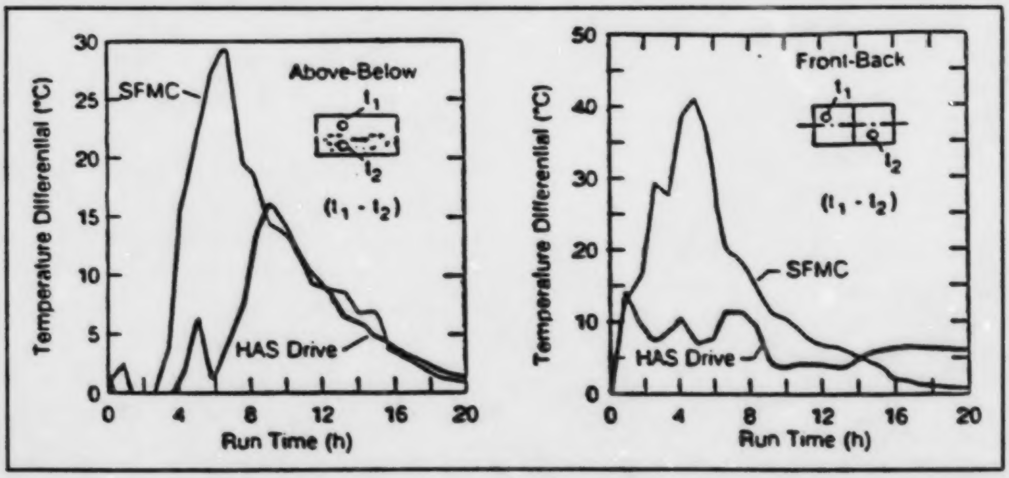


Figure 7. Bulk temperature — SFMC vs. HASDrive experiment: (a) temperature above axial communication vs. temperature below and (b) temperature in the first half of the pack (injection side) vs. temperature in the second half of the pack.

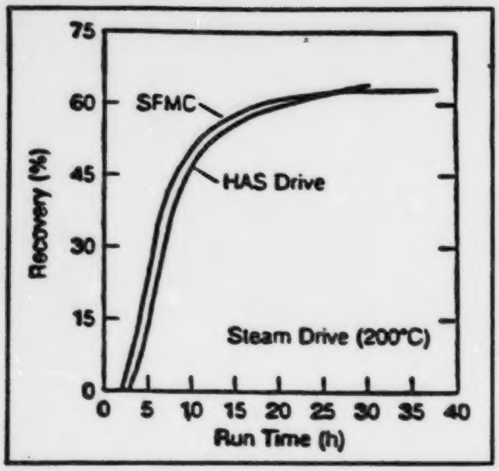


Figure 8. Recovery for SFMC and HASDrive laboratory-simulated processes.

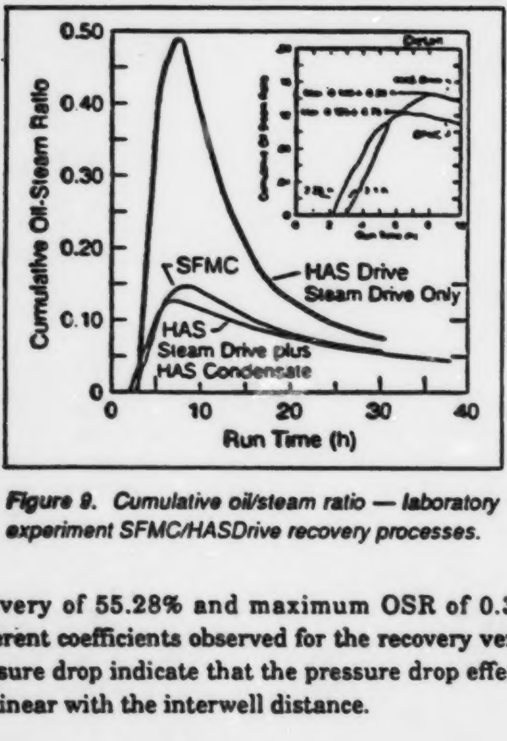


Figure 9. Cumulative oil/steam ratio — laboratory experiment SFMC/HASDrive recovery processes.

recovery of 55.28% and maximum OSR of 0.302. Different coefficients observed for the recovery versus pressure drop indicate that the pressure drop effect is not linear with the interwell distance.

Constant Interwell Pressure Drop (SFMC)

Constant injection rate offers the best conditions for laboratory investigations, and for calibration of the computer model prior to field-scale simulation. However, comparative studies of SFMC and HASDrive processes use the same pressure drop value of 1.4 MPa (200 psi). This condition is achievable for most oil sand reservoirs at depths greater than approximately 80 m (250'). For this condition, the steam injection rate was allowed to float.

The Effect of Channel Position Permeability and Number

In order to investigate the relative contributions of gravity drainage and steam drive mechanisms in relation to channel position, the recovery process was compared for both "bottom" and "axial" (middle) channel positions.

Figures 11a and b illustrate the OSR for both of these situations. Permeability contrasts (oil and/channel) of 0.8 mm^2 and 1.2/35 mm^2 are shown.

The middle-channel position is favorable for an axial drag-dominated recovery process.

The bottom-channel position is favorable for a gravity drainage-dominated process. As can be observed, a permeability variation from 0.8 to 1.2 mm^2 is sufficient to switch the dominance of the controlling recovery mechanism from drag (Figure 11a) to gravity drainage (Figure 11b).

The effect of channel permeability on maximum achievable OSR is illustrated in Figure 12, summarizing results from 25 computer-simulated runs. The occurrence of an optimal channel permeability is observed for each situation as a result of flow rate increase and drag reduction acting contrarily.

The abrupt transition from a "zero injectivity" situation o a high-yield process took place over a relatively small (approximately 3 μm^2) interval of change in channel permeability (Figure 12). The critical channel permeability depends on both formation permeability and channel position.

For a constant pressure drop injection mode, higher injectivities are achieved by increasing the number of channel levels. Therefore, increasing the number of levels is likely to produce the reservoir more rapidly, but sometimes a lower OSR. Another factor to be considered before making a decision on the number of channels should be the risk of plugging

Table 3. Sand and fluid properties used for numerical simulation

		BU		[SI]
Porosity, % bulk volume			32.6	
Absolute liquid permeability, µmp^2				
Sand-filled channel			5.00	
Tar sand			0.90	
Sand-filled layer			1.08	
PV compressibility, psi^{-1}	[kPa^{-1}]	1.10^{-5}		[$0.154\ 10^{-5}$]
Heat capacity, Btu/ft^3 · °F	[kJ/m^3 · °C]			
Reservoir rock		36		[2400]
Thermal conductivity, Btu/ft · D · °F	[J/m · D · °C]			
Reservoir rock		55		[4]
Cap and base rock		55		[4]
Water/oil and gas/oil capillary pressure		0		
Irreducible water saturation, %PV			12.64	
Residual tar sand saturation, %PV			20	
Reservoir bitumen				
Density at 15 psia and 212°F, lbm/ft^3		60		
at 103 kPa and 100°C,	[g/cm^3]			[0.96]
Compressibility, psi^{-1}	[kPa^{-1}]	5.10^{-6}		[$0.7\ 10^{-6}$]
Thermal expansion coefficient, 1/°F	[1/°C]	0.0034		[0.0061]
Heat capacity, Btu/lbm°F	[kJ/°C · kg]	0.66		[2.76]
Dissolved gas and distillable components		none		
Viscosity, cp (mPa·s) (1) Athabasca		(1)		(2)
(2) Cold Lake				
at 194°F (90°C)		370		146.6
at 212°F (100°C)		213		94.0
at 320°F (160°C)		20		13.5
Experiment temperature, °F	[°C]	81		[27]
Temperature of reservoir, °F	[°C]	48		[9.0]
Pressure gradient, psi/ft	[kPa/m]	4.71		[9.9]
Water saturation, %PV				
Perforated tar sands			99.0	
Nonperforated dense streaks			12.7	
Tar sand saturation, %PV				
Perforated tar sands			1	
Nonperforated dense streaks			87.3	
Tar sand viscosity, cp (mPa·s)			1,747,000	

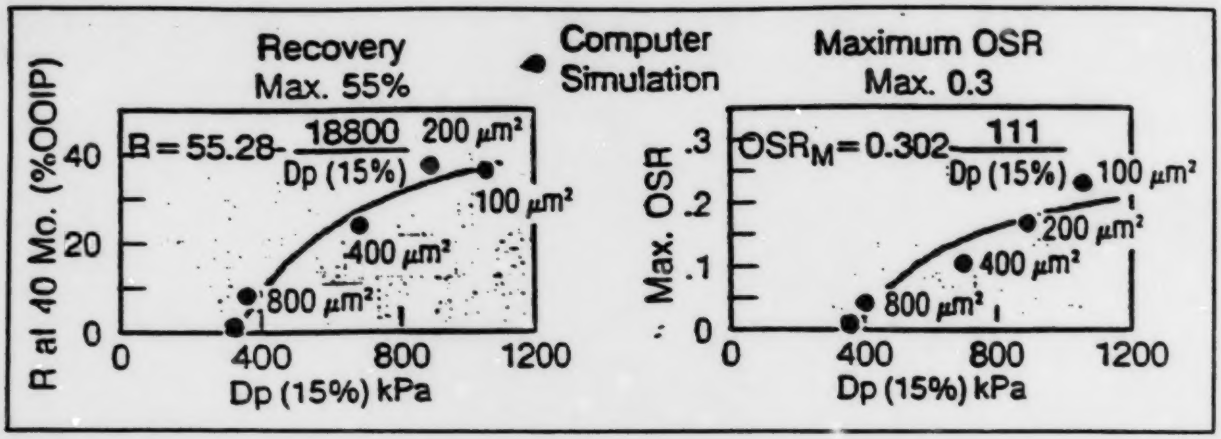


Figure 10. Effect of channel permeability on recovery (a) and maximum oil/steam ratio (10 t/d steam at 200°C) (b) at constant injection rate.

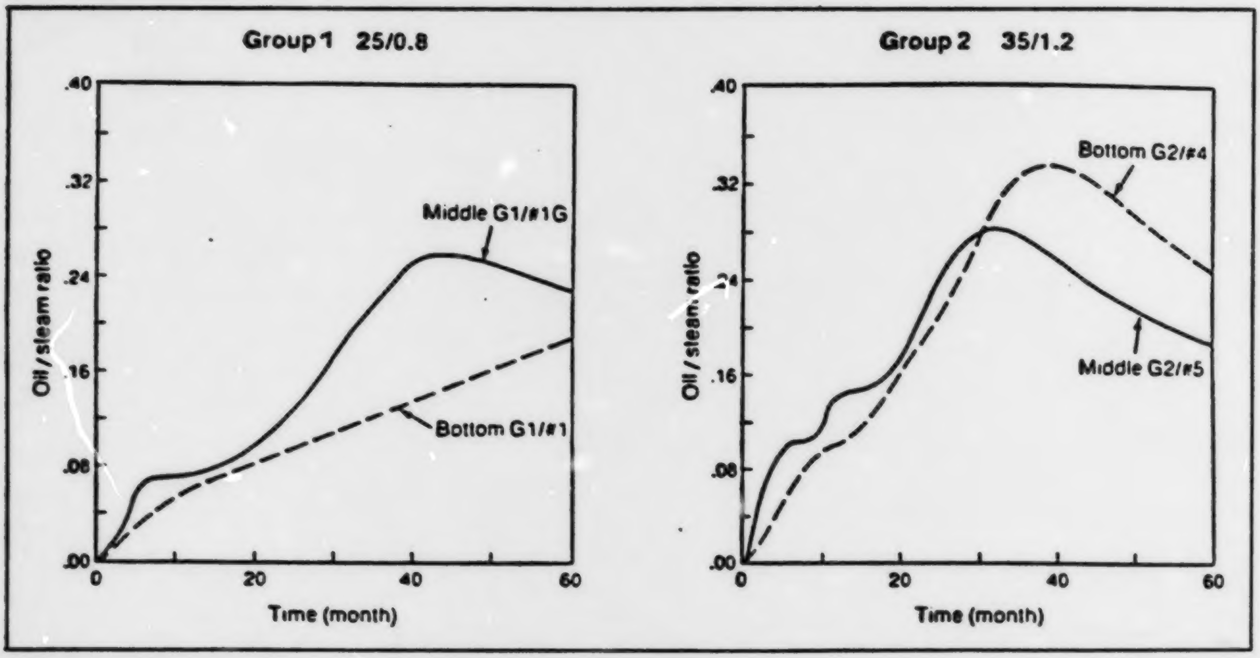


Figure 11. Oil/steam ratio for single channel; oil sand permeability 0.8 µm² channel permeability 25 µm² (a) oil sand permeability 4.2 µm² channel permeability 35 µm² (b).

during the initial stages of injection; this risk is reduced with increasing numbers of levels.

Based on OSR criteria, it was observed that increasing the number of channels will always reduce the time to achieve maximum OSR, regardless of formation or channel permeabilities, although the effect on maximum OSR will depend on the particular permeabilities encountered.

Figures 13a to 13c illustrate the results of the computer stimulation study and indicate the

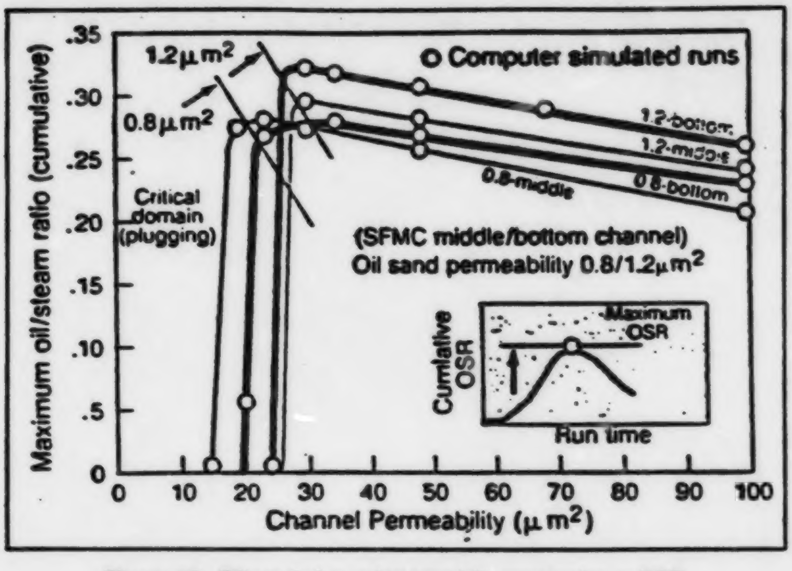


Figure 12. Effect of channel permeability on maximum OSR.

variation in maximum OSR and time to reach it with increasing numbers of levels. For low oil sand permeability (0.8 mm²) the two-channel situation indicates a maximum OSR (Figure 13a); for higher oil and permeability the maximum OSR oil decrease with the number of levels (Figures 13b, c).

However, regardless of permeability conditions, increasing the number of levels will always reduce the time to achieve maximum OSR and final recovery.

To reduce the number of variables involved in the description of the recovery process and reduce the number of criteria required for the comparison of the two processes, the net present value (NPV) should be calculated.

SFMC Versus HASDrive Sensitivity Study, A Combined HAS-pipe/SFMC Process

For comparing recovery processes using the SFMC or the HASDrive, a model of 20 m x 20 m x 60 m thermally insulated on the lateral sides and conducting heal to the cap and base rock was used (Figure 14). A double 15" diameter horizontal borehole filled with 25 mm² sand or a double 3" (7.62 cm) HAS-pipe communicating between injection and production vertical wells situated at 6.5 m from the base rock were typified as the SFMC or the HASDrive models respectively. A symmetrical grid geometry, each side having 6 x 3 x 5 blocks was used. A constant pressure drop injection strategy was applied for an investigated situations; the production pressure was depth at 170 kPa; steam quality of 80% was injected and the injection temperature vas therefore a function of the constant pressure drop regime. The HAS-pipe was kept at saturation temperature and the "equivalent HAS-steam" was calculated from thermal balance of the pipe.

A new "combined" process was designed to eliminate the high plugging ride observed with SFMC at low pressure drop regimes and to enhance the drive steam rate during the initial stages of the HASDrive process. In order to achieve this, a HAS-pipe of 3" (7.6 cm) diameter was embedded in the and-filled borehole of 15" (38 cm) diameter. The SFMC, HASDrive, and combined steam drive processes were further ~~compared using~~ numerical simulation.

The Effect of Formation Depth

For the permeability and size of the boreholes and the HAS-pipe used in this model, a 2 to 3 MPa pressure drop is observed to be a critical range for both the SFMC and HASDrive processes.

The SFMC plugs at 2 MPa while the drive injectivity is negligible during the first 2 years of the HASDrive process. Figure 14 illustrates maximum achievable recovery at 1, 2, and 3 years for the HASDrive, SFMC, and combined steam recovery processes (Figure 15). The combined process indicates the best situation for all pressures and at any elapsed time. For a pressure range of 2 to 2.5 MPa the HASDrive appears to be a safe but relatively slow recovery process.

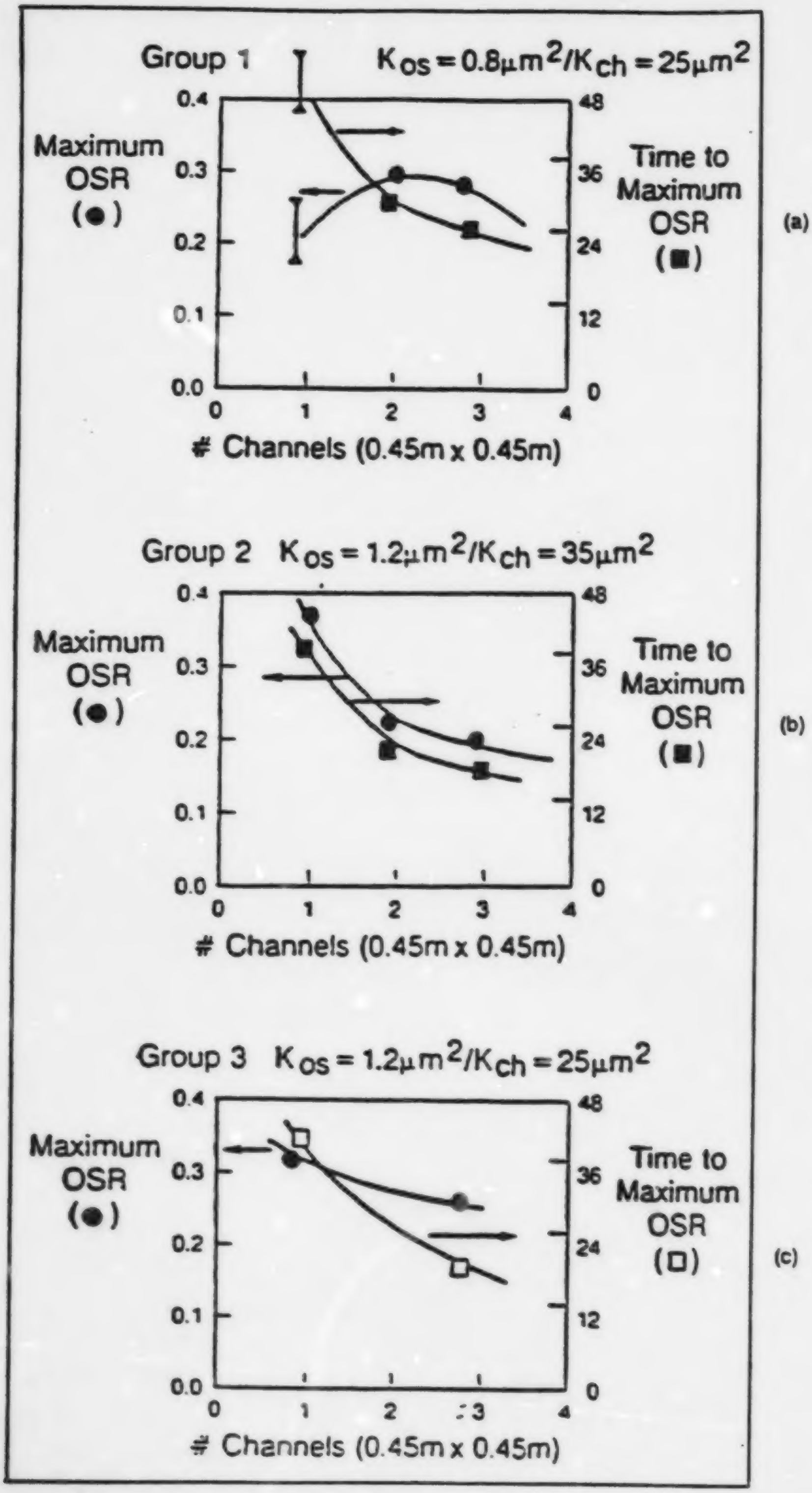


Figure 13. *Influence of number of channels on maximum oil/steam ratio; low permeability oil sand-standard channel permeability (a) high permeability oil sand-high channel permeability (b) and high permeability oil sand-standard channel permeability (c).*

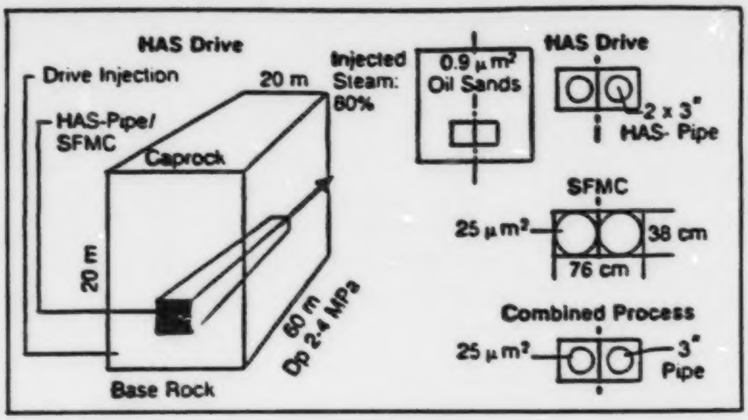

HAS Drive
Drive Injection
20 m
HAS-Pipe/
SFMC
Caprock
20 m
60 m
Dp 2.4 MPa
Base Rock
Injected
Steam:
80%
0.9 μm²
Oil Sands
HAS Drive
2 x 3"
HAS- Pipe
SFMC
25 μm²
38 cm
76 cm
Combined Process
25 μm²
3"
Pipe

Figure 14. Model used for numerical simulation-HASDrive-SFMC-combined process.

For pressure drop in excess of 3 MPa (depth in excess of 130 m) the SFMC indicates higher recovery rates than HASDrive.

Viscosity Effect

Figure 16 illustrates the recovery and OSR versus time for HASDrive and for combined processes when Athabasca and Cold Lake viscosities are compared. A shift of the recovery curve a approximately 1 year is observed; the shift is slightly larger for the HASDrive process than for the combined one. At 3.5 MPa the positive influence of

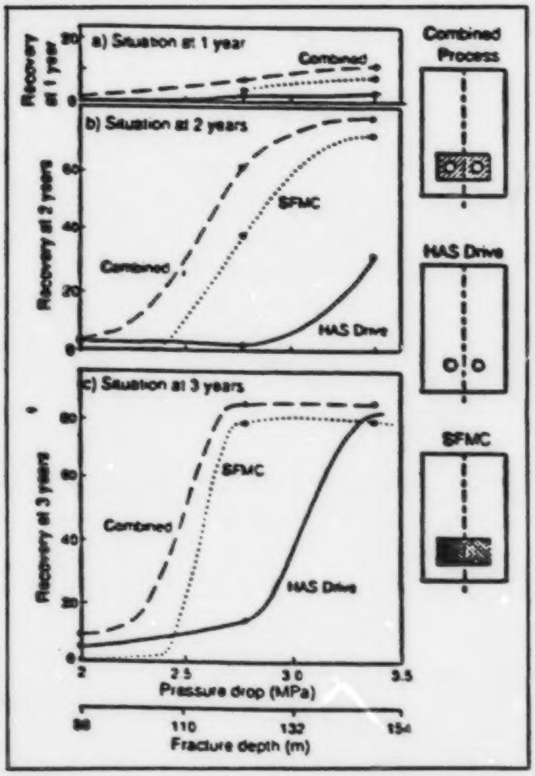


Figure 15. Recovery as a function for total pressure drop-comparison of the HASDrive, SFMC, and combined.

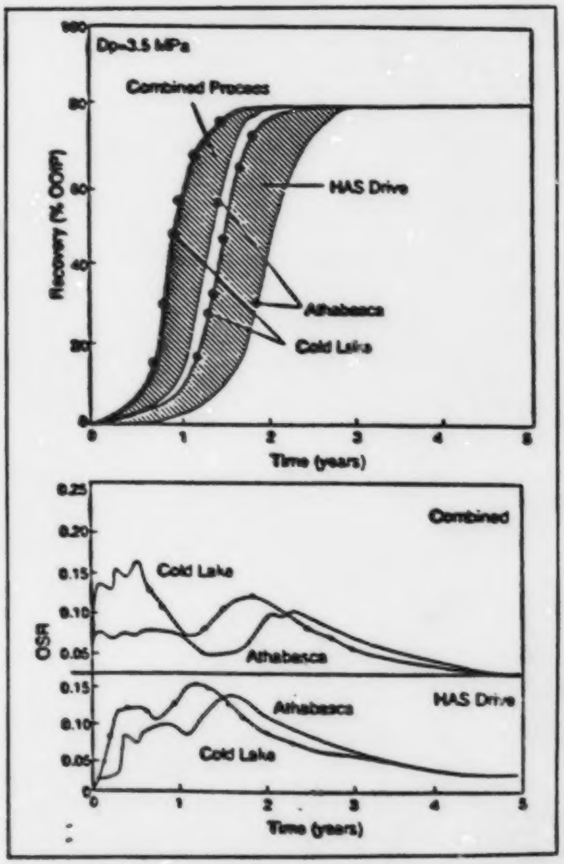


Figure 16. Viscosity effect.

viscosity reduction on OSR is more important for the combined than for the HASDrive process.

CONCLUSIONS

The following conclusions are supported by the experimental and numerical analysis presented in this paper:

1. Steam drive recovery processes using HASDrive or SFMC completion of horizontal boreholes are capable of producing comparable final recovery situations.
2. A new completion of the horizontal borehole using a HAS-pipe imbedded in a permeable sand filling (combined process) is suggested to eliminate the plugging risk observed for the SFMC, and o increase the initial recovery rate and low injectivity observed for the HASDrive.

   Laboratory observations of temperature development indicate a localized recovery process progressing from the injection end to the production end for SFMC, and an almost uniform, radial progression of temperature contours around the HAS-pipe.
3. The following are potential advantages of the SFMC steam drive process:
   - transportation of steam and oil emulsions from injectors to producers, and diversion of hot fluids into the adjacent oil sand zone;
   - enhancement of flow and heat transfer between the ho sand-channel flow zone and the active recovery zone, by elimination of slotted or perforated wells with a limited open area;
   - increase in interfacial area between the sand-filled channels and oil sand zones;
   - and rapid heating.
4. Two main recovery mechanisms operate synergistically during the SFMC recovery processes: steam drive and gravity. When average formation permeability is 0.8 μm^2 or lower, the steam drive mechanism dominates the process, whereas gravity will dominate for permeabilities of 1.2 μm^2 or greater.
5. The permeability of the sand-filled channel is one of the essential characteristics of the system. An optimal value of channel permeability appears to depend on formation permeability.
6. For shallow reservoirs containing extra-heavy oil where pressure cannot exceed 2 to 2.5 MPa, the SFMC process indicates a plugging risk while the HASDrive process progresses al a at a very slow recovery rate.

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SESSION IV
Recovery Technology

STEAM-ASSISTED GRAVITY DRAINAGE — A GENERAL REVIEW

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Although the steam-assisted gravity drainage process has application in the recovery of conventional heavy oils, it was originally conceived for the recovery of bitumen where the in situ viscosity is so high that conventional production methods are impractical.[1,2]

The quantity of bitumen in place in Canadian reservoirs is as large as that for conventional crude oil in the Middle East.[3] Thus, the challenge of developing suitable methods for recovery is of very great practical importance. In the main Canadian reservoirs — Athabasca, Cold Lake and Peace River, the bitumen is essentially immobile and injection of fluids is usually very difficult. In situ recovery methods generally depend upon heating the bitumen in order to reduce its viscosity; both heating with steam and in situ combustion have been used.

One of the main problems encountered is that, even if the bitumen is heated, it cannot be pushed through cold reservoir without regaining its lost viscosity and thus preventing adequate flow. It is necessary to keep the bitumen hot as it flows to the production well. One scheme for doing this which has been studied is reverse combustion.[4] In this approach, the tar sand is ignited near the production well and the flame front moves away against the flow of the combustion air which is injected into another well. A major problem is obtaining adequate air injectivity. Another problem, and an even larger one, is that secondary combustion fronts tend to occur near the injection well and this has caused the process to be unsuccessful.[5]

Another approach is that of cyclic steam stimulation. In this method, steam is first injected into the reservoir through the production well; in bitumen reservoirs, it is frequently necessary to use injection pressures high enough to cause reservoir fracturing so that injectivity can be obtained. The reservoir region adjacent to the well becomes heated and then, subsequently, the flow is reversed to allow production. This continues until the flow has declined to uneconomic values and then the cycle is repeated. This is the process which has been used by Esso Resources Canada in its very successful and large commercial project at Cold Lake.[6–8] The process is relatively efficient and oil flows of the order of 100 barrels per day are obtained with oil/steam ratios of about 0.3. The main problems with the method are associated with the high well density required (about 1.5 ha per well) and the relatively low economic recovery (15–20%).

A problem with the cyclic steaming method is that there is little drive available to move the hot fluids to the well. It is thought that some of the drive comes from the recompaction of the fractured reservoir and some from gravity drainage around the well.[9] The problem with gravity drainage, in this application, is that the conventional (i.e., near vertical) wells which are employed have a rather limited contact with the reservoir and the need for radial flow provides a considerable resistance. A major advantage of cyclic steaming is that the heat tends to be concentrated where it can do the most good, i.e., nearer to the well bore.

The steam-assisted gravity drainage approach which is reviewed in this paper employs gravity drainage to move the crude to the production well but the contact with the reservoir is much greater because horizontal wells, and potentially very long horizontal wells, are employed; these have much greater contact with the reservoir than do conventional wells and adequate flows can be achieved with heads equivalent to that obtained from gravity. The process allows the oil to remain hot as it drains downwards and there is a systematic coverage f the reservoir o that high recoveries can be achieved.

THE INITIAL CONCEPT

The mechanism by which the process proceeds and the general nature of the flows within the reservoir are indicated by the diagram in Figure 1.

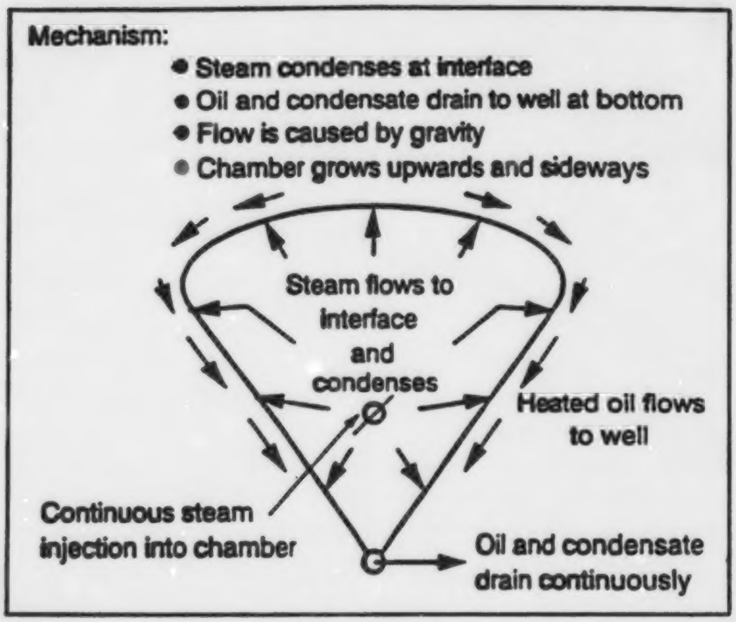
Mechanism:
• Steam condenses at interface
• Oil and condensate drain to well at bottom
• Flow is caused by gravity
• Chamber grows upwards and sideways
Steam flows to interface and condenses
Heated oil flows to well
Continuous steam injection into chamber
Oil and condensate drain continuously

Figure 1. Conceptual diagram of the steam-assisted gravity drainage process.

This shows the process in a fairly early phase. Steam is being injected from a well, typically a horizontal well, which lies somewhat above the horizontal producer. A steam saturated zone is formed in which the temperature is essentially that of the injected steam. The steam flows to the perimeter of the steam chamber and condenses. The heat from the steam is transferred by thermal conduction into the surrounding reservoir. The water condensate from the stem and the heated oil flow, driven by gravity, to the production well below. As the oil flows away and is produced, the steam chamber expands. It can expand both wards and sideways.

The growth upwards proceeds in a rather irregular but quite rapid manner until it is limited by the top of the reservoir. The upwardly moving interface tends to be in the form of steam fingers with oil flowing between them in a rather erratic manner. The flows meander.[13]

In contrast, the interface moves sideways and downwards in a very stable manner; it is stabilized by gravity. This part of the mechanism tends to be rate limiting and is much more amenable to theoretical analysis than the rise of the interface. The nature of the process is such that there is a systematic displacement of the cold oil by the steam and the oil remains hot as it flows to the lower production well.

A later stage in the process, where the chamber has reached the top of the reservoir and is spreading sideways beneath the overburden is shown in Figure 2. The similarity between the situation shown here and the coning of gas in conventional production operations is apparent. If product is removed too quickly from the horizontal production well then the steam chamber will be drawn down to the well and bypassing will occur. Essentially the only drive available to move oil to the well comes from the effect of gravity and the mobile oil is that which is relatively close to the steam chamber. The process is ineffective with vertical wells because of the relatively low flows that can be achieved under these condition. However, with long horizontal wells, economic flows can be achieved. For example, in conventional reservoirs, a 1000 metre horizontal well on a 4 hectare spacing[1] has a productivity index which is about 100 times that of a conventional well. In the situation shown in Figure 2, the oil drains quite slowly per nit length of the well (about 0.15 m^3/m of well/day or 0.5 USG/foot of well/hour), but the total flow can be quite large because of the long length.

With long wells, the process is basically a two dimensional one involving linear flow, although there is an end effect which augments the flow somewhat.[10]

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[1] With such a spacing, the distance between adjacent wells normal to their length would be about 40 metres.

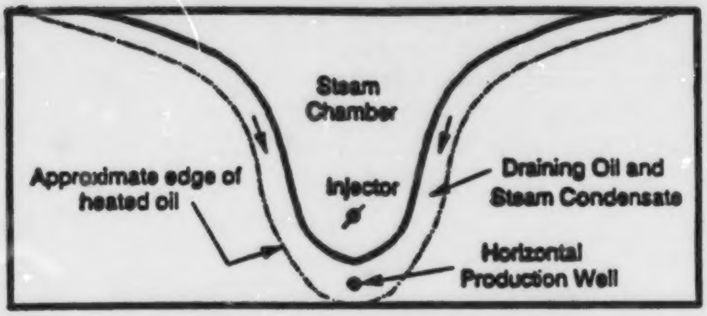
Steam Chamber
Approximate edge of heated oil
Injector
Draining Oil and Steam Condensate
Horizontal Production Well

Figure 2. Cross-sectional diagram showing the steam-assisted gravity drainage process with the chamber in contact with the overburden. In a commercial project, the lateral spreading of the steam chamber becomes limited when it joins similar chambers on either side. After this, the rate gradually declines as the head available to create drainage decreases.

PROCESS MECHANISM

Figure 3 illustrates the starting point for the analysis of the rate of flow. Only the results of this analysis will be discussed here; the details are available elsewhere.[11] It is assumed that the only means for transferring heat into the cold reservoir is by thermal conduction normal to the steam condensation surface which is called the "interface". This interface is advancing. In the element shown in Figure 3 the interface is advancing at a velocity U. The temperature distribution ahead of the advancing front depends upon the thermal diffusivity of the reservoir and the velocity at which the front is advancing.

In the original theory, it is assumed that the temperature distribution ahead of the front corresponds to a steady state. The drainage in each element of the reservoir is assumed to be parallel to the interface. The rate is calculated using Darcy's law, using the gravity gradient resolved along the angle of the interface, and the density difference between the flowing oil and the steam to determine the potential gradient. A constant effective permeability is assumed. The viscosity of the oil depends upon the temperature of the element. There is a coupling of the equations because the temperature distribution depends upon the front velocity, the oil flow depends upon the temperature distribution and the front velocity is determined from the oil flow gradient by means of a material balance.

For example, a higher reservoir permeability has the effect of creating a higher flow rate which in turn creates a higher interface advance rate and this in turn lowers the flow rate because of the lower penetration of heat beyond the interface.

The original analysis of this problem led to the following equation for the rate of drainage.[1]

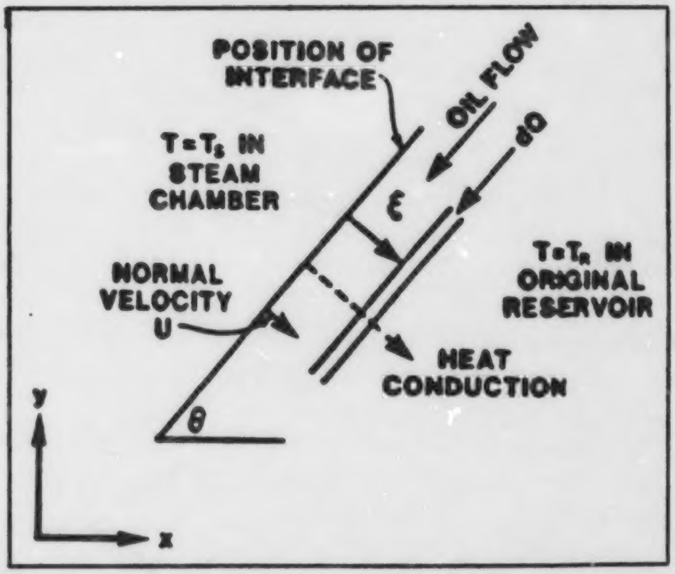

Figure 3. The basic mechanism of steam-assisted gravity drainage. Heat is transferred from the chamber by thermal conduction. This mobilizes the oil around the perimeter of the chamber and this drains downwards driven by gravity. As the oil drains, the chamber grows larger. The rate of advance of the condensation surface (the "interface") is controlled by a material balance; its rate of advance depends upon the increase in the flow of oil at the point being considered.

$$(1)\quad q = 2L\sqrt{\frac{2kg\alpha\phi\Delta S_o h}{m\nu_s}}$$

$$\frac{1}{m\nu_s} = \int_{T_R}^{T_S}\left(\frac{1}{\nu} - \frac{1}{\nu_R}\right)\frac{dT}{T-T_R}$$

where	g	acceleration due to gravity $m \cdot s^{-2}$
	h	reservoir height m
	k	effective permeability for oil flow m^2
	L	length of horizontal well m
	m	dimensionless parameter (typically 3–4) which is determined by the viscosity-temperature characteristics of the oil, T_R and T_S as shown above
	q	oil flow rate to production well $m^3 \cdot s^{-1}$
	α	thermal diffusivity of reservoir $m^2 \cdot s^{-1}$
	μ	oil viscosity Pa·s
	ϕ	fractional porosity of reservoir
	ΔS_O	initial fractional oil saturation less residual oil saturation in steam chamber
	ν	kinematic viscosity of the oil at T°C $m^2 \cdot s^{-1}$
	ν_R	kinematic viscosity of the oil at T_R°C $m^2 \cdot s^{-1}$
	ν_S	kinematic viscosity of the oil at T_S°C $m^2 \cdot s^{-1}$

This equation is dimensionally correct and any consistent set of units can be employed; SI units are shown above.

Equation 1 can be used to estimate the production rate for a particular reservoir. Alternatively, this rate can be looked upon as the critical production rate beyond which steam coning will occur. An interesting feature of equation 1 is that each of the variables under the square root sign is equally important. Thus, for example, changing any of them by a factor of 2 will change the rate by a factor equal to the square root of 2. The rate is proportional to the length of the well. The square root dependence arises because of the coupling between the heat transfer and oil drainage mechanisms. For example, increasing permeability increases the rate but tends to decrease the thickness of the heated oil layer. Similarly, increasing thermal diffusivity increases the thickness of the heated oil layer and also increases rate.

The original equation (1) tends to overestimate the drainage rate because it assumes that the temperature distribution corresponds to the steady state everywhere along the interface. In practice, this is nearly true in the central part of the interface, but it cannot be true at the ends. Modifications known as TANDRAIN and LINDRAIN have been made to the original theory which allow for these effects. Probably the LINDRAIN assumptions give the most realistic answer; these result in changing the factor 2 underneath the square root sign to 1.3. This has the effect of reducing the predicted flow to about 80% of that given by (1).

	Value of factor under square root
Original theory[1]	2
TanDrain[2]	1.5 interfaces are straight at bottom
LinDrain[11]	1.3 interfaces are straight

A more elaborate approach for predicting the rate of drainage has been described in the literature which involves breaking the interface into a number of segments and following, in a stepwise calculation, the buildup of heat beyond them.[12] This provides answers which are quite similar to those found from the equations discussed here.[11]

PREDICTED DRAINAGE RATES

The predicted drainage rates for three crude oils in a particular reservoir are shown in Figure 4 as a function of steam temperature. The values which were chosen for the parameters are shown in the caption to the figure. The value for permeability, k, of 0.4 μm² (0.4 Darcy) includes an allowance for the effect of relative permeability. The value of k used in the equation corresponds to the average effective permeability. Because the water condensate has to run through the reservoir with the oil, it is necessary

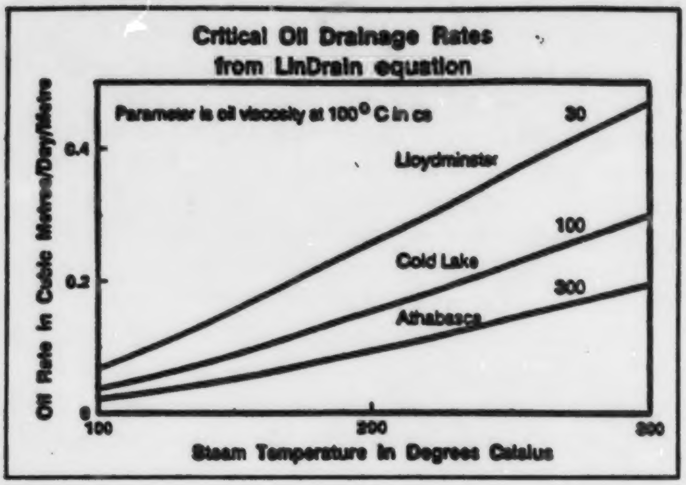

Figure 4. Calculated drainage rates for 3 crude oils. The following properties were assumed: S_o *0.825;* S_{or} *0.175; f 0.325; k 0.4* μm^2*; a* $8 \times 10^{-7}\ m^2 \cdot s^{-1}$*; h 20 m;* T_R *12°C.*

to reduce the absolute permeability. It is customary to employ a value of 0.4 for the relative permeability to allow for this. Thus the 0.4 μm^2 in Figure 4 corresponds to a reservoir having a permeability of 1 μm^2.

The calculated rates in Figure 4 range from about 0.01 m^3/day/m to over 0.4 (1 m^3/d/m = 1.92 B/d/ft). For example, Cold Lake crude would be produced at a rate of about 0.15 m^3/d/m with a steam temperature of 200°C; for a well length of 1000 m, this would be equivalent to 150 m^3/d or 290 B/d.

SAGD PRODUCTION OF BITUMEN

A significant problem in the application of steam-assisted gravity drainage to the production of bitumen lies in establishing the initial communication between the injection and production wells. This is necessary so that condensate from the steam can be removed and allow further steam to flow into the reservoir and continue heating.

A method of accomplishing this is to use an injection well which is above but close to the production well. The intervening bitumen can be mobilized by heating both the injection and production wells and by applying a pressure difference between them. A horizontal injection well can be used and this has the advantage of providing steam over the entire length rapidly. Vertical injectors have also been used; this approach has the advantage of allowing the point of steam injection to be raised as the project matures. However, it also has the disadvantage that steam is not supplied along the length of the production well and some time is required for the steam chamber to grow along the axis of the well.[10]

A means for establishing communication which has not been tried in the field would involve the initial injection of steam at fracturing pressure. If the wells were located with their axes in the direction of the fracture trend, this could allow a rapid heating of a plane vertically above the horizontal well and along its length.

Figure 5 shows the vertical separation between the producer and injector which ill allow steam breakthrough after a period of one year for the particular conditions shown. This is calculated from the equation for the cold displacement of the oil from

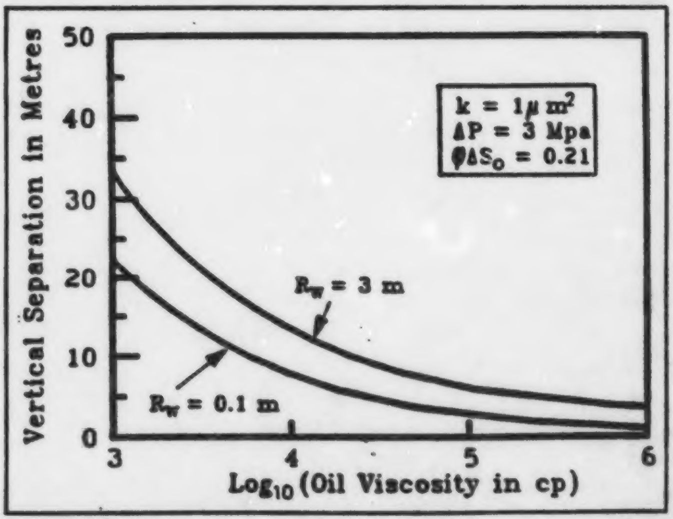

Figure 5. Approximate allowable separation between horizontal injector and producer for 1 year breakthrough time.

the reservoir.[11] This rate of displacement is dependent upon the radii of the wells because it is limited by the radial flow in their vicinity. It is reasonable to assume a radius considerably larger than that of the actual well because of the wellbore heating which would be going on simultaneously. Reservoir oils with a viscosity of less than 10,000 cp allow quite wide separations between the injector and the producer. However, for bitumens having viscosities of 100,000 cp or more, it is necessary to reduce the separation to 5 m or less.

If the approach of using closely spaced injectors and producers is employed for the production of bitumen, then the process starts with the steam chamber rising through the reservoir to the overburden. This is relatively rapid with rise rates of the order of 0.1 m/d. Methods for estimating these are available.[11,13] Following the rise to the top of the reservoir there is a spreading and then a depletion phase to the process. The production rate increases quite rapidly during the chamber rise period, reaches a maximum and then declines as the process proceeds. Figure 6 provides a means for estimating the rate of production as a function of time.[11] In this figure, a dimensionless production rate is plotted against the ultimate recovery of oil.

Figure 7 shows the isotherms which were measured in a high pressure, two-dimensional scaled model experiment which represented a section of a reservoir containing five parallel horizontal wells with injector located closely above.[14] Five separate steam chambers grew upwards in the early parts of the experiment. These coalesced before they reached the top and at the end of the experiment the reservoir was almost entirely depleted. From experiments of this type it was possible to predict the performance for held scale operations.

Figure 8 shows the cumulative production, per well, for systems such as this with three different well spacings.[14] The conditions correspond to those in Athabasca in AOSTRA's Underground Test Facility. With a ell spacing of 11 m, production levels off after about 2 years. With higher well spacing the production continues longer. The main advantage of closer well pacing is that the oil/steam ratio is better because of the shorter time which is necessary to keep the reservoir hot. On the other hand, close well spacing involves a higher cost for constructing the wells and, as a result there is an economic optimum. The oil/steam ratio can be predicted and computer programs are available.[11]

In AOSTRA's Underground Test Facility project the well spacing was 24 m and excellent results are said to have been obtained.[15–17] An enlarged project with three pairs of wells 500 m long is under construction.[17]

PRODUCTION OF CONVENTIONAL HEAVY OIL

In Figure 5 it was shown that conventional heavy oil could be produced by steam-assisted gravity drainage with the injection well located near to the top of the reservoir. Figure 9 shows how this might be done with a reservoir which also has a bottom water layer.[18] The operations are controlled so that

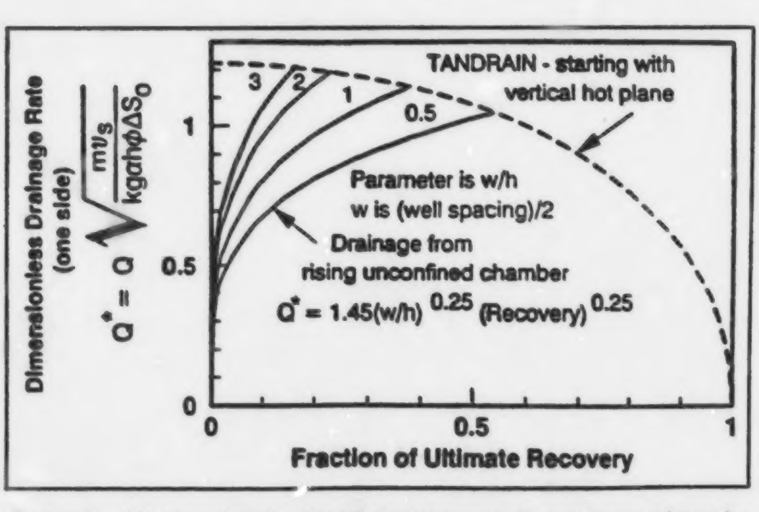

Figure 6. Diagram showing the oil drainage rate for a system where the chamber rises and is then constrained by the vertical boundaries of the pattern. The symbols are the same as for equation 1; w is half of the horizontal spacing between adjacent production wells.

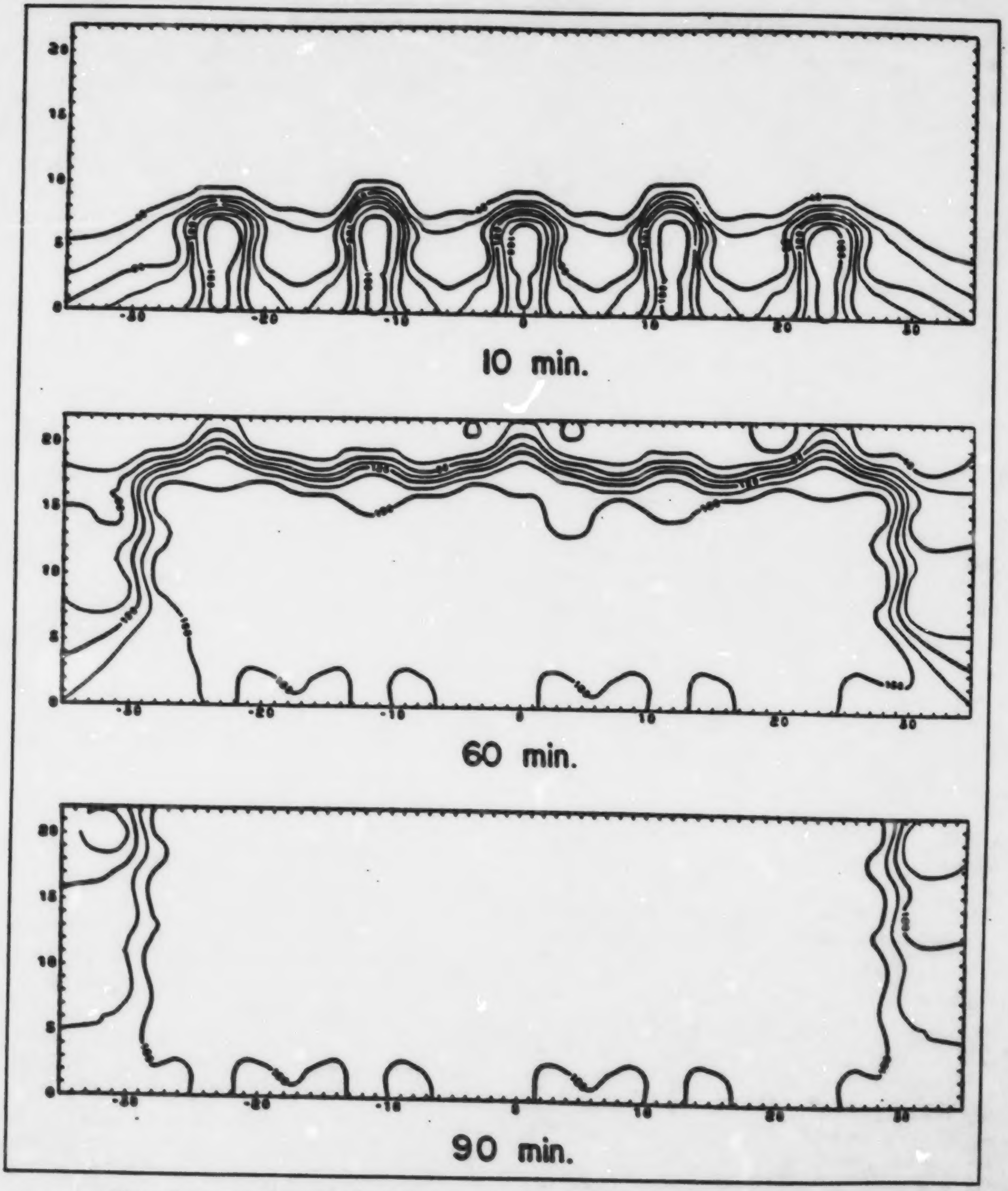

Figure 7. Measured isotherms in a laboratory model which represents 5 parallel horizontal well-pairs.

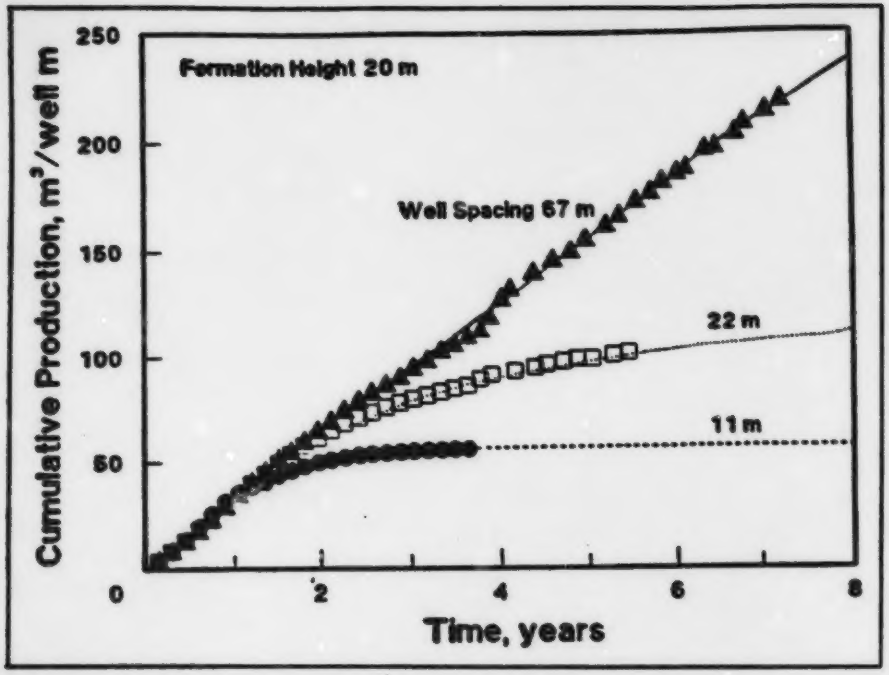

Figure 8. Cumulative bitumen production for infinite well pairs at the UTF site in the Athabasca Tar Sands — data from scaled model experiments. Short wells would be expected to give substantially higher rates because of end effects.

the production well pressure is nearly equal to that of the aquifer so as to control water production.

During the first phase of this type of operation, the steam chamber moves downward and cold oil and condensate from the steam are displaced to the production well. The rate at which this process occurs and the quantity of oil which is recovered can be estimated.[11,19] Once the steam zone reaches the vicinity of the production well, the production temperature increases and the normal steam-assisted gravity drainage process can be carried out. This concept has been tested in a series of scaled model experiments.[16]

Figure 10 shows isotherms which were obtained in one of these experiments towards the end of the production. It was found that good recoveries could be obtained with little heat loss to the underlying water. It was also shown that excellent operation could be obtained even if the production well were below the initial water-oil contact. In this circumstance, water was displaced from around the production well by oil in the initial stages of the experiment.

A field pilot is being operated by Sceptre Resources which is closely related to the principles described here.[20] Very high production rates have been achieved in the first year or so of operation and the project is considered encouraging.

CONCLUSIONS

In steam-assisted gravity drainage, the use of horizontal production wells provides a large contact with the reservoir and this allows operation at economic rates without the bypassing of steam.

The process can be used for both the production of bitumens and for the production of conventional heavy crude oils. The drainage rates depend upon the crude viscosity at steam temperature ad reservoir properties (equation 1 and Figure 4). With bitumens, the problem of obtaining initial communication between the injection well and the production well, so that the steam condensate can be removed, can be overcome by placing the in section wells close to and above the production wells. Oil which is heated around the perimeter of the steam chamber can drain to the production well without cooling. This approach has been demonstrated successfully in the Athabasca tar sands by AOSTRA at their UTF facility. Scaled model experiments and theory indicate that such projects, with 20–25 m well spacings, should be able to achieve recoveries of over 50% with a project life of about 2 to 3 years. Larger spacings are probably more economic in most circumstances.

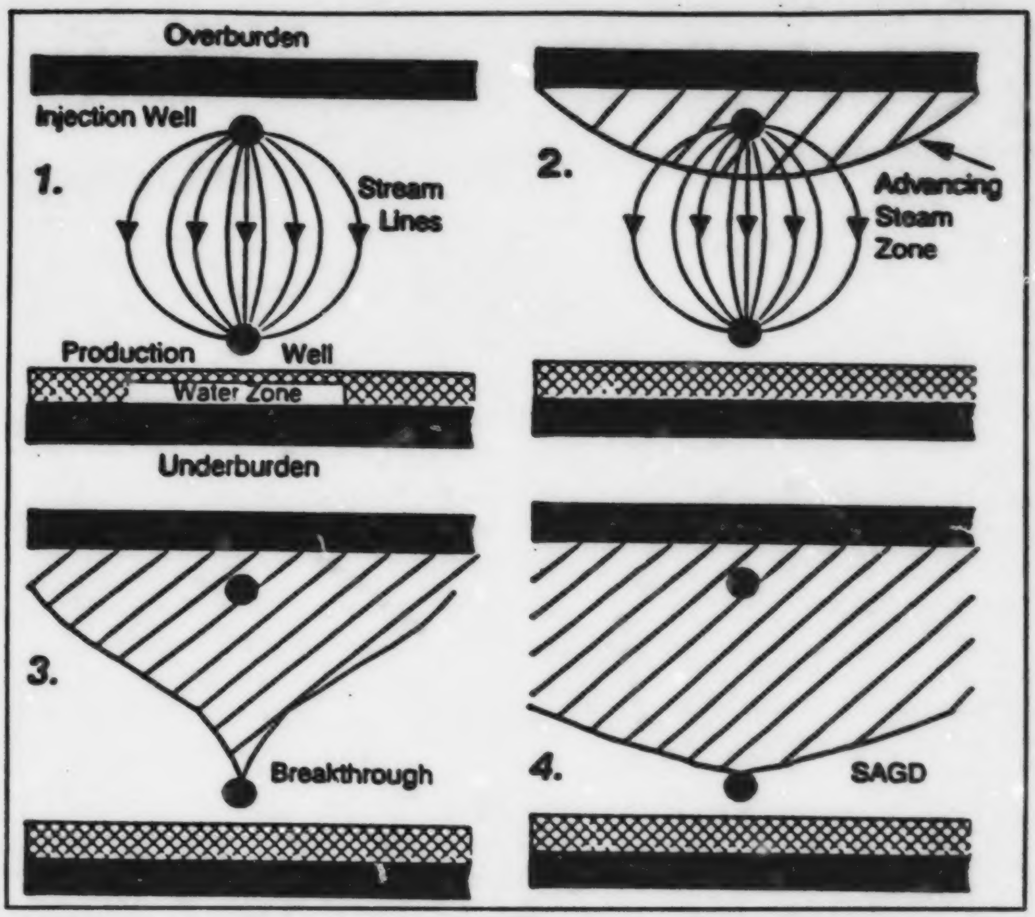
Overburden
Injection Well
1.
Stream Lines
Production Well
Water Zone
Underburden
2.
Advancing Steam Zone
3.
Breakthrough
4.
SAGD

***Figure 9.** Diagrams showing the concept of using SAGD for the production of conventional heavy crude oil which lie over bottom water. The initial mobility of the oil allows vertical displacement downwards as in 1 and 2.*

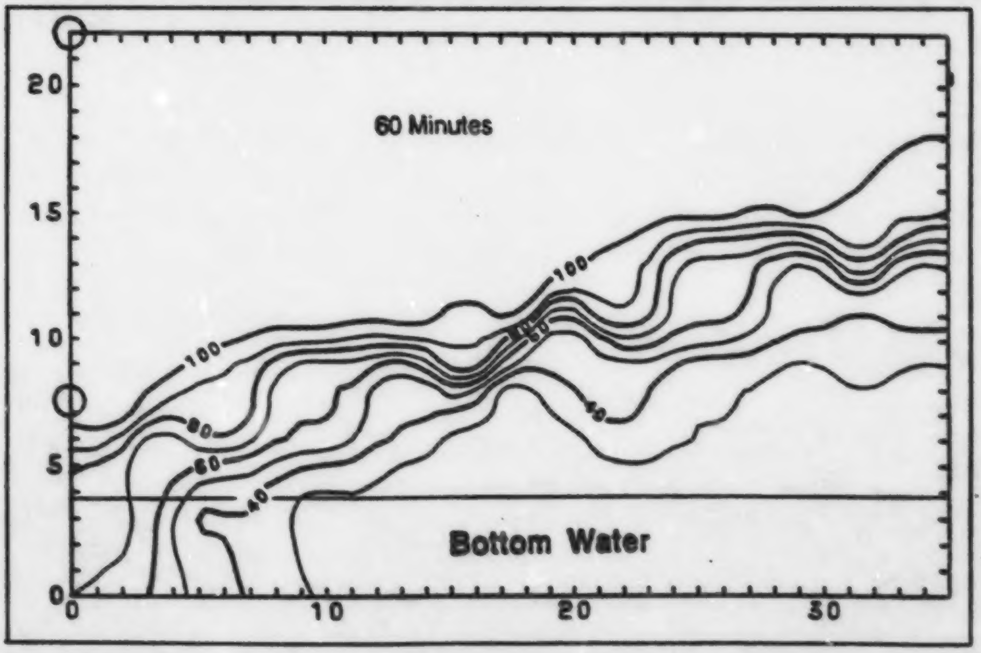

***Figure 10.** Diagram shoring the positions of isotherms in a scaled-model experiment which demonstrates the process of Figure 9. In this experiment, the bottom water was connected to a large constant pressure supply; water flow either in or out was very small because of the balanced pressure. In the situation shown, little heat has penetrated into the bottom water, even though most of the oil has been drained.*

Steam-assisted gravity drainage can also be used for the production of heavy oils with a significant initial mobility and steam can be injected from horizontal wells near to the top of the reservoir. During the initial establishment of thermal communication, cold oil is displaced efficiently by the growing steam chamber above the production well. Following this initial phase, the process is similar to that used for bitumen, but usually faster. A promising pilot project along these lines is operated by Sceptre Resources in the Tangleflags near to Lloydminster, Saskatchewan.

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NUMERICAL SIMULATION OF WELLBORE EFFECTS IN STEAM-ASSISTED GRAVITY DRAINAGE PROCESS

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ABSTRACT

This paper presents a coupled reservoir and well model in which the equations are solved simultaneously using Newton's method. The equations for the circulation well include The frictional pressure drop and the heat transfer between tubing flow and annulus flow.

Numerical predictions of single-well and two-well scenarios of the steam-assisted gravity drainage (SAGD) process are presented. It was found that ignoring the frictional pressure drop in The injection tubing would overestimate oil production rates. The frictional pressure drop in the annulus caused uneven fluid injection/production along the wells, and reduced the thermal efficiency of the process.

The heat-exchanger effect influenced the shape of the steam zone in the reservoir. Furthermore, the ultimate oil recovery of the SAGD process seems unaltered by the pressure drop and heat-exchanger effect.

INTRODUCTION

A promising method for the in situ recovery of bitumen with horizontal wells is the steam-assisted gravity drainage (SAGD). Steam is injected continuously above a horizontal producer. The heated oil drains by gravity to the producer and allows the formation and expansion of a steam chamber. In this process, the oil should be removed at the maximum rate without steam production.[1] Steam can be injected through a horizontal well as in AOSTRA's Underground Test Facility,[2,3] or a vertical well as in Esso's Cold Lake Project.[4]

The conventional two-well SAGD method is applied to oil sands pay thickness of 25 meters or greater. Hence, there is a need to find a recovery method for thin reservoirs (thickness less than 25 meters).[5,6] This paper examines through numerical simulation the performance of two SAGD processes, namely (a) a single-well method using cyclic steam injection, (b) a conventional two-well method.

OIL RECOVERY MECHANISM

In the single-well method a long horizontal well is placed near the bottom of a thin reservoir (Figure 1). The well which consists of a tubing and a slotted liner, is subject to cyclic steam injection.

During the injection cycle, steam is circulated down the tubing and back through the annulus as

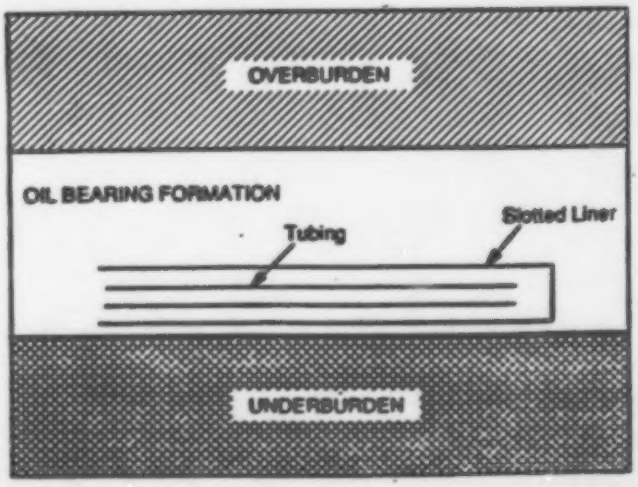

Figure 1. Schematic diagram of a horizontal well using SAGD process.

shown in Figure 2A. The bitumen and reservoir rock adjacent to the wellbore is heated by both convection and conduction. Steam leaks into the reservoir through the perforated liner and condenses. The latent heat released raises the temperature of the bitumen and reservoir rock. At the same time, heat is also transferred by conduction through the reservoir rock.

In the production cycle, fluids are produced through the annulus as shown in Figure 2B. Fluids that are liquid in the reservoir may flash in The annulus because of the lower pressure. No flow occurs in the tubing in the production cycle.

Through a series of injection and production cycles, a steam chamber can form and grow as bitumen is mobilized and drained from the reservoir.

The two-well SAGD method is a continuous process in which the oil is removed at maximum rate without steam production. Both single-well and two-well methods involve complex interactions between reservoir and wellbore fluids. Therefore, it is necessary to solve the reservoir and wellbore flow equations simultaneously.

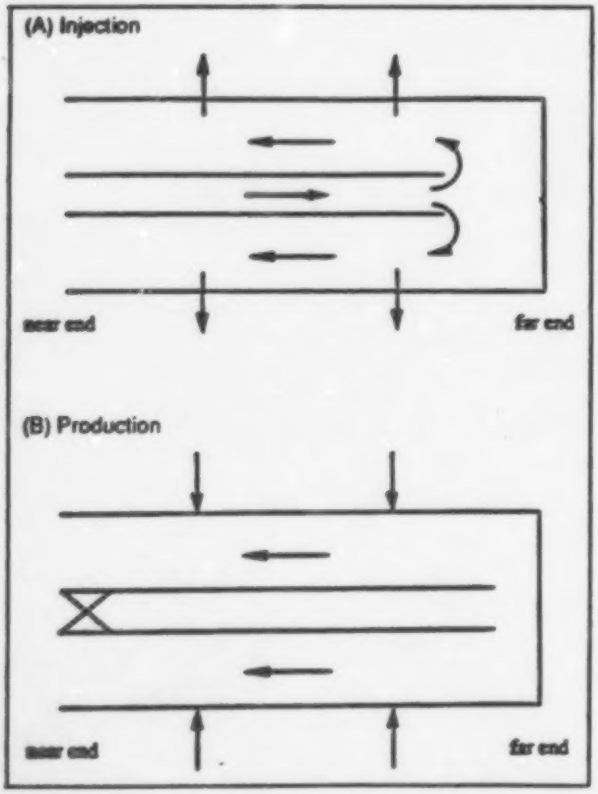

Figure 2. Flow directions in circulation well.

This paper describes a simulator that handles rigorously the coupling of reservoir and wellbore equations, and its application in the predictions of the performance of single-well and two-well SAGD processes.

A coupled reservoir/wellbore simulator was previously described in Stone et al.[7] However, the numerical techniques used in the paper as well as the process simulated are different.

EQUATIONS AND SOLUTION TECHNIQUES

Outline

The detailed simulation of reservoir and wellbore flow of the process depicted in Figure 1 entails the simultaneous solution of the reservoir equations and wellbore equations. In this section, the equations for a two-component water/dead oil fluid system are shown and the solution method is described.

Reservoir Equations

The reservoir equations consist of material balance equations for each component, an energy balance equation, and a constraint equation. For a water/dead oil fluid system, the following discretized equations can be written:

- Material balance equation for the water component

$$(1)\quad \Delta T_w \Delta\psi_w + \Delta T_g \Delta\psi_g + \rho_w q_w + \rho_g q_g - \frac{V_r}{\Delta t}\delta\left[\phi\left(S_w\rho_w + S_g\rho_g\right)\right] = 0$$

- Material balance equation for the dead oil component

$$(2)\quad \Delta T_o \Delta\psi_o + \rho_o q_o - \frac{V_r}{\Delta t}\delta\left[\phi\rho_o S_o\right] = 0$$

- **Energy balance equation**

$$\sum_j \Delta T_j h_j \Delta w_j + \Delta T_c \Delta T + \sum_j h_j \rho_j q_j - q_{loss} + q_{ar} - \frac{V_r}{\Delta t}\delta\left[\phi\sum_j \rho_j S_j e_j + (1-\phi)\rho_r e_r\right] = 0 \qquad j = o, g, w \tag{3}$$

where q_{loss} is the heat loss by conduction to cap rocks, and q_{ar} is the energy transfer by conduction between the annulus and the reservoir.

- **Phase constraint equation**

  Equation (4a) is used when there is no gas; otherwise, Equation (4b) is used

$$S_o + S_w = 1 \tag{4a}$$

$$y_w = 1 \tag{4b}$$

Wellbore Equations

The discretized equations for flow in the tubing and annulus are

- **Total mass conservation equation**

$$\Delta A\sum_j \rho_j \alpha_j u_j - \sum_j \rho_j q_j - \frac{V_w}{\Delta t}\delta\left[\rho_j\right] = 0 \qquad j = o, g, w \tag{5}$$

- **Momentum conservation equation**

$$\Delta\left(\sum_j \rho_j \alpha_j u_j u_j\right) + \Delta p + \frac{V_w}{A}\sum_j\left(\rho_j \alpha_j\right) g \sin\theta$$

$$\Delta p_f - \frac{V_w}{A \cdot \Delta t}\delta\left[\sum_j \rho_j \alpha_j u_j\right] = 0 \tag{6}$$

- **Energy conservation equation**

$$\Delta A\left(\sum_j \rho_j \alpha_j e_j u_j\right) + pA\Delta\left(\sum_j \alpha_j u_j\right) - \sum_j h_j \rho_j q_j - q_{at} - q_{ar} - \frac{V_w}{\Delta t}\left[\sum_j \rho_j \alpha_j e_j\right] = 0 \qquad j = o, g, w \tag{7}$$

where q_{at} is the energy transfer between annulus flow and tubing flow.

- **Water conservation equation**

$$\Delta A\left(\rho_w \alpha_w u_w + \rho_g \alpha_g u_g\right) - \rho_w q_w - \rho_g q_g - \frac{V_w}{\Delta t}\delta\left[m_w\right] = 0 \tag{8}$$

- **Constraint equation**

$$\left(\rho_w \alpha_w + \rho_g \alpha_g\right) + \rho_o \alpha_o - \left(m_w + m_o\right) = 0 \tag{9}$$

In Equations (8) and (9), m_i (i = w, o) are global molar density of Component i.

The relationships between the phase velocities are governed by two-phase flow correlations.[8] To model three phase flow it is a common practice to assume $u_w = u_o$. If homogeneous flow is assumed, all phase velocities are equal ($u_o = u_g = u_w$).

The heat transfer between the tubing and annulus is given by the following expression

$$q_{at} = 2\pi\Delta x\, U_{at}\left(T_a - T_t\right) \tag{10}$$

where U_{at} represent the overall heat transfer coefficient which includes film condensation or boiling heat transfer at tubing wall surfaces and heat conduction through the tubing wall.[9]

Coupling Terms

The reservoir and wellbore are coupled through the convection and conduction exchange terms.

The volumetric flow rates between reservoir and wellbore are:

Injection:

$$(11)\quad q_j = I_{we}\,\lambda_t\,\Delta x\,(p_w - p_{res})$$

where

$$(12)\quad \lambda_t = \sum_j \left(k_{rj}/\mu_j\right)_{res} \qquad j = o, g, w$$

Production:

$$(13)\quad q_j = I_{we}\,\lambda_j\,\Delta x\,(p_w - p_{res})$$

where

$$(14)\quad \lambda_j = \left(k_{rj}/\mu_j\right)_{res} \qquad j = o, g, w$$

The well indices I_{we} are evaluated as in Peaceman.[10] The evaluation of mobilities in Equations (12) and (14) follows Williamson and Chappelear.[11]

The material transfer through convection is then $\rho_j\, q_j$ and the respective energy transfer is $h_j\, \rho_j\, q_j$.

An expression for energy transfer through conduction between annulus and reservoir can be derived using an approach similar to Peaceman's[10] approach for well source/sink terms:

$$(15)\quad q_{ar} = \frac{2\pi\Delta x}{\ln\left(r_o/r_w\right)}\,K\,\left(T_w - T_r\right)$$

with

$$(16)\quad r_o = 0.14\left(\Delta y^2 + \Delta z^2\right)^{1/2}$$

K = thermal conductivity of rock

Boundary Conditions and Steam Production Control

During steam injection, steam is injected down the tubing and back through the annulus (Figure 2a). The pressure and enthalpy of steam are specified at the tubing inlet and the fluid volumetric flow rate is imposed at the annulus outlet. This set of boundary conditions allows the simulator to handle the rapidly changing injectivity with ease.

When the well is under production (Figure 2b), pressure is specified at the annulus outlet. Note that there is no flow in the tubing in this case.

To optimize the efficiency of the process, steam production is minimized during the injection and production cycle by controlling the pressure at the outlet of the annulus. The rates are adjusted such that the outlet pressure is a few hundred kPa above the water saturation pressure.[6]

Solution Technique

All reservoir and wellbore flow equations are discretized using the fully implicit technique. A staggered grid system as described in Siu et al.[12] is used to represent the wellbore. The reservoir primary unknowns in each block[13] are p, S_o, S_w, and T and the wellbore primary unknowns are p, h, m_w, m_o, and u_g. The reservoir and wellbore equations are solved simultaneously at each timestep using Newton's method. Figure 3 shows the Jacobian matrix structure for a two-well model. The shaded area represents that of a single-well model.

To determine the saturations in the wellbore given p, h, m_w, and m_o, isenthalpic flash calculations are performed as described in Agarwal et al.[14]

NUMERICAL PREDICTIONS

The purpose of this numerical study is to examine how the oil recovery is affected by the pressure drop and heat-exchanger effect in a circulation well. The heat-exchanger effect refers to the heat transfer between tubing fluid and annulus fluid. There was no

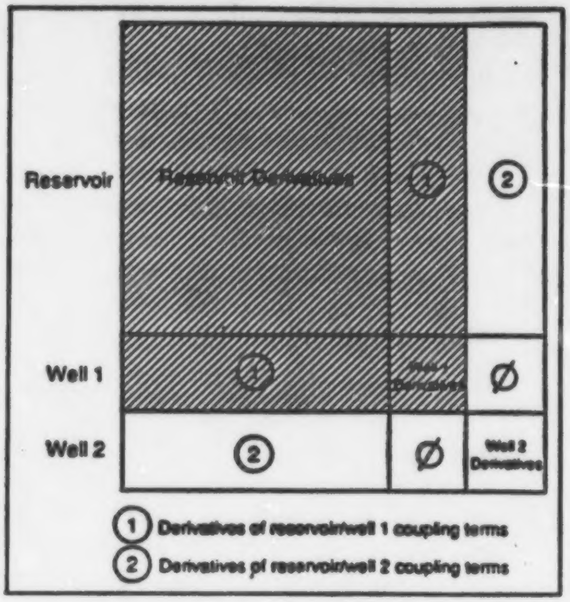
Reservoir
Well 1
Well 2
Reservoir Derivatives
1
2
1
Well 1 Derivatives
Ø
2
Ø
Well 2 Derivatives
1 Derivatives of reservoir/well 1 coupling terms
2 Derivatives pf reservoir/well 2 coupling terms

Figure 3. Jacobian Matrix structure.

attempt to optimize the thermal efficiency of the process, nor to use a fine grid to simulate accurately the movement of The steam and temperature fronts.[15]

Table 1. Input data for cyclic steam injection

Reservoir:	
thickness, m	16.0
horizontal permeability, m^2	4.0×10^{-12}
vertical permeability, m^2	1.0×10^{-12}
porosity	0.35
heal capacity, kJ/m^3-K	2347.0
thermal conductivity, kJ/m-d-K	149.5
average pressure, kPa	450.0
temperature, °C	11.0
S_{oi}	0.81
S_{wi}	0.19
Bitumen Properties:	
molacular weight, kg/kg	600.0
mole density, kg/m^3	1034.0
compressibility, kPa^{-1}	7.25×10^{-7}
thermal expansion, $°C^{-1}$	6.84×10^{-4}
heat capacity, kj/m^3-K	2164.0
viscosity at 10°C, mPa·s	1.57×10^{6}
viscosity at 250°C, mPa·s	3.0
Wellbore:	
length, m	300.0
inner diameter of tubing, m	0.090
outer diameter of tubing, m	0.101
inner diameter of casing, m	0.159
outer diameter of casing, m	0.178

Single-Well Simulations

The coupled reservoir/well model was tested using data reported in Best et al.[16] Table 1 gives the data employed in this study.

Figure 4 depicts a 4 x 4 x 5 reservoir grid representing half of a single-well pattern. The 300 m well was completed through four blocks in the bottom layer to take advantage of the force of gravity.

Dry steam was circulated in the well at 3000 kPa to heat up the immobile bitumen. The outlet pressure was controlled so that steam production was minimized. This implied that just enough steam was injected to mobilize the bitumen without loss of energy in the production. After about 80 days of healing, the well was shut in for 0.4 days; then it was switched to a constant-pressure production at 2000 kPa. When the bitumen production became small, the well was switched back to constant-pressure injection. The injection rate decreased with time as the reservoir pressure built up. Once the injection rate became small, the well was shut in for 0.4 days again. Then, it was re-opened for production. Simulation of this process was stopped after 90 cycles of steam injection.

Three different cases were devised to examine the importance of frictional pressure drop and heat-exchanger effect in the wellbore. These results are presented as follows.

Presence of pressure drop and heat exchanger effect. The steam-chamber growth is depicted in Figure 5. The volume of the steam-chamber in the reservoir increased with each cycle. In general, it contracted during an injection cycle and expanded during a production cycle. Furthermore, it was observed that the cycle duration increased as the steam-chamber volume increased.

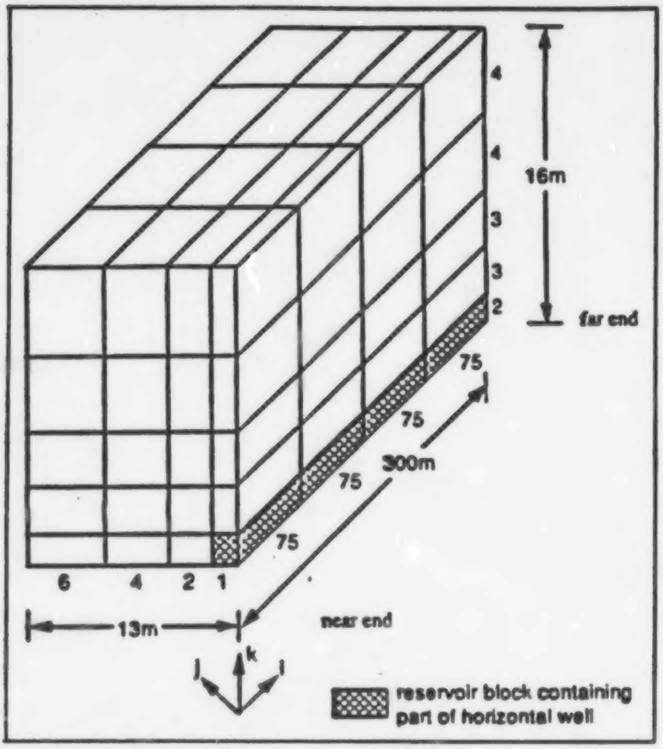

Figure 4. Reservoir/wellbore grid model.

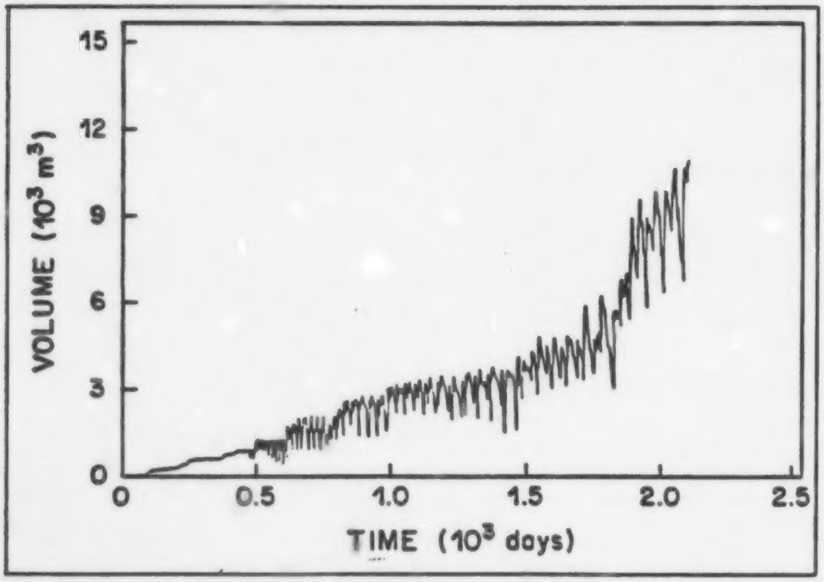

Figure 5. Steam chamber growth.

Figure 6 shows the cumulative oil production curve which is made up of a series of small steps of various sizes. The production curve rises during the production cycles, and remains constant during injection and shut in periods. The oil production in early cycles are very small which are reflected by the small steps. As the steam-chamber size increased, the rate of oil production also increased. The cumulative oil production after 90 cycles of injection was 9360 m^3 for the half pattern, i.e., a recovery of 46.9% OOIP in 2103 days. Note that this is not the ultimate recovery for the process. The oil-steam ratio (OSR) was 0.21 at the end of simulation.

The well plays an important part in the oil recovery process. Figure 7 shows the percentage of energy transferred to the reservoir along the well. It is observed that more energy was injected near the production end (near end), 28.9% compared to 17.1% at the far end block. If the injection were distributed evenly, each block would have injected 25.0% of the total energy.

The oil production percentages are presented in Figure 8. The oil production were 30.1% from the near-end well block and 15.2% from the far-end block. The trend of these curves is consistent with the energy injection curves, i.e., more oil is produced from places where more energy had been injected. This result is reasonable because the main recovery mechanisms are viscosity reduction and gravity drainage.

Figure 9 depicts the gas saturation contours in the reservoir at the end of 90 cycles. At the near end the steam formed a typical V-shaped chamber spanning from the well to the top of the reservoir. At the far end the steam just formed a small pocket above the well. Therefore, the steam swept the near end preferentially. This result is consistent with the energy and mass transfer along the well.

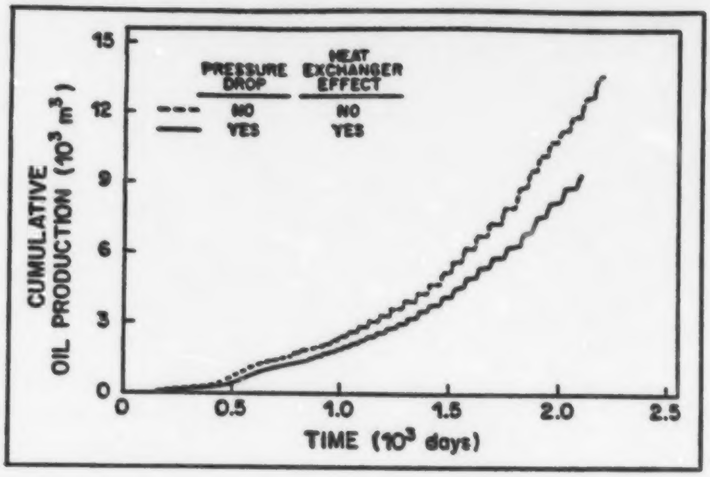

Figure 6. Cumulative oil production.

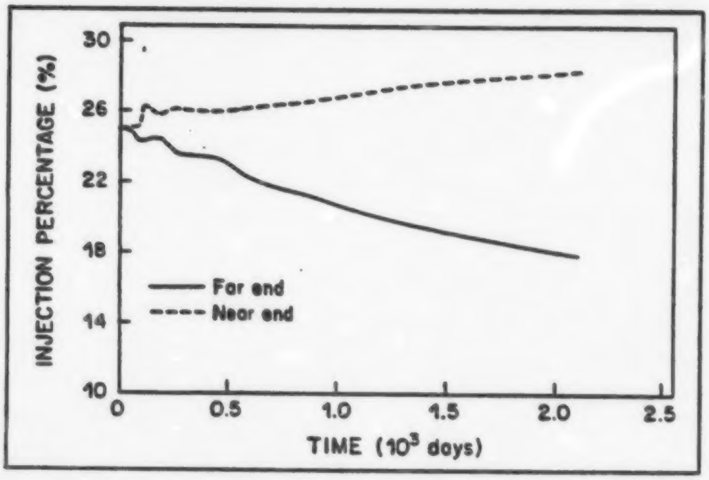

Figure 7. Cumulative energy injection percentage.

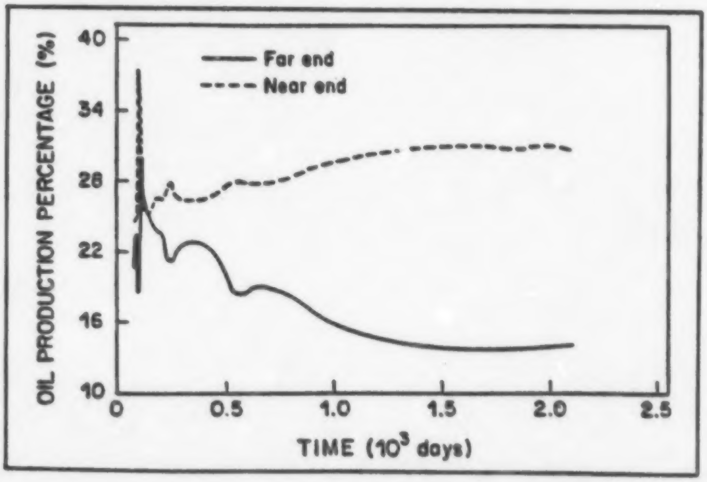

Figure 8. Cumulative oil production percentage.

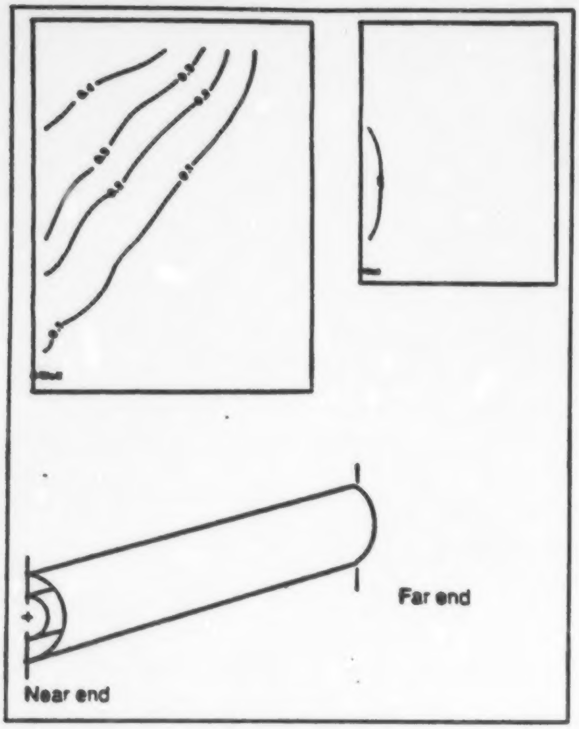

Figure 9. Gas saturation contours in reservoir.

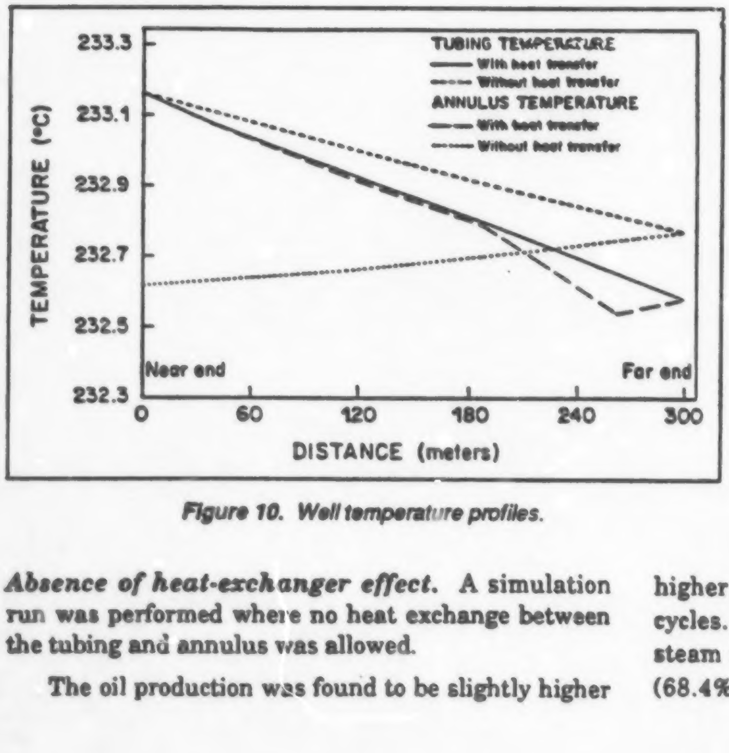

Figure 10. Well temperature profiles.

Absence of heat-exchanger effect. A simulation run was performed where no heat exchange between the tubing and annulus was allowed.

The oil production was found to be slightly higher at the beginning than in the case with heat-exchanger effect, but increased at a slower pace. At the end, the oil production was about 1% lower, and with the same OSR of 0.21.

The major difference, however, was in the volumetric sweep in the reservoir. Without the heat-exchanger effect, 21.0% of the injection energy entered the reservoir from the near-end well block, and 28.5% from the far-end. Consequently, the oil production was 19.0% from the near end, and 29.8% from the far end. Therefore, the injection steam tended to sweep the far end.

It appears that the heat-exchanger effect dictates where the steam goes. Figure 10 compares the temperature profile in the well at the end of the fifth injection cycle. Without the heat-exchanger effect, the fluid temperature in the annulus decreased monotonically from the far end to the near end. A higher temperature at the far end provided the least resistant path for the steam to enter into the reservoir. However, with the heat-exchanger effect, the temperature first dropped and then rose again. The fluid in the annulus became superheated as it flowed towards the production end. Therefore, the steam tended to sweep the near end. Also shown in this diagram are the temperature profiles in the tubing. The drop in tubing temperature was larger in the heat-exchanger case because of a higher flowrate.

Absence of pressure drop and heat-exchanger effect. By ignoring both the pressure drop and heat-exchanger effect, the energy injections through each well block are about the same. It follows from the previous discussion that the oil productions from each block are also the same. In addition, the well pressure in the annulus is higher because of zero pressure drop in the tubing. This allows higher injection rates and slightly longer injection cycles. It took 2203 days to complete 90 cycles of steam injection. The oil production was 13660 m^3 (68.4% OOIP) compared to 9360 m^3 as shown in

Figure 6. This represents a 46% over-prediction in oil production. The OSR was 0.24 after 90 cycles.

Two-Well Simulations

The same reservoir and wellbore geometry data were used, except that the reservoir thickness was increased to 26 m. Due to an additional well being used, a finer grid of 5 x 4 x 10 was constructed.

In the two-well runs, dry steam was injected continuously at a constant pressure of 3000 kPa, the producer was initially maintained at 2800 kPa and the production pressure was increased as soon as steam was produced. The simulation runs were terminated by a minimum oil rate of 0.5 m^3/d.

The same three different cases as in the single-well simulations were performed using a well Length of 500 m. Figure 11 compares the cumulative oil productions. By ignoring the pressure drop, one sees early production of oil because of higher effective injection pressure. This leads to a reservoir life of 3304 days. With pressure drop included the reservoir life was extended to 4063 days with heat-exchanger effect and 4515 days without the heat-exchanger effect. The ultimate oil recovery for the three cases were almost the same at 78% OOIP.

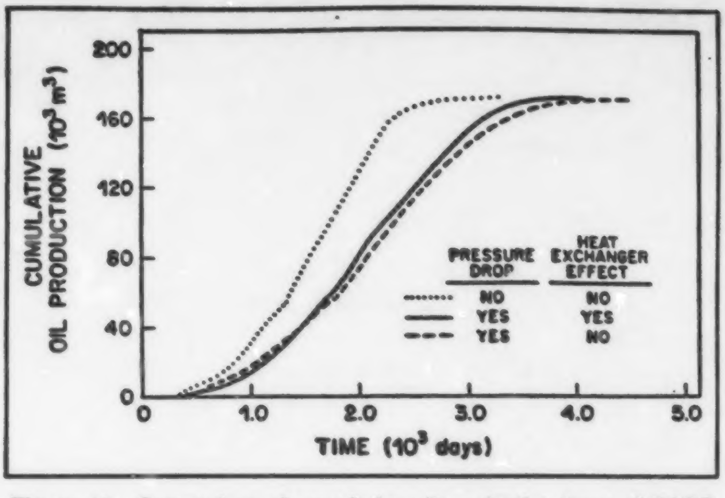

Figure 11. Comparison of cumulative oil production two-well SAGD Process.

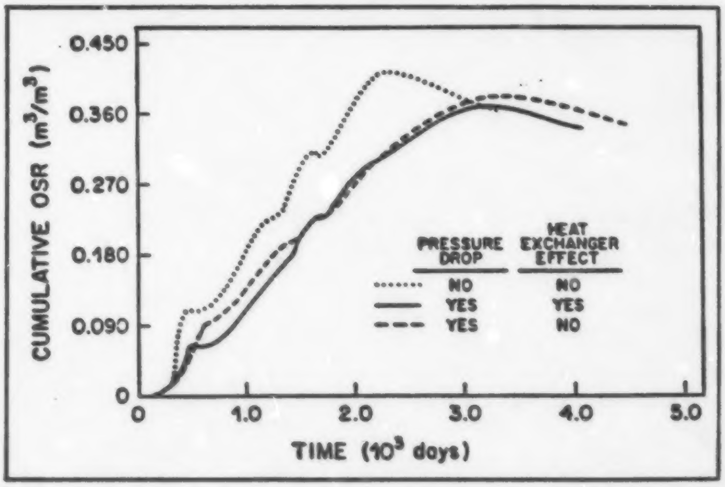

Figure 12. Comparison of cumulative OSR two-well SAGD Process.

A comparison of cumulative OSR is shown in Figure 12. By assuming no pressure drop in the wells the OSR reached a maximum of 0.41 at 2323 days and a value of 0.36 at termination. The high values of OSR indicate uniform growth of steam chamber along the well axis. Including the pressure drop the maximum OSR dropped to 0.37 with heat-exchanger effect and 0.38 without the heat-exchanger effect. Both cases terminated with an OSR of 0.34. The lower OSR values in these two cases are results of pre-mature steam breakthrough. With the heat-exchanger effect steam first broke through at the near end, and without the heat-exchanger effect steam first broke through at the far end. These findings are consistent with the single-well results.

Closure

Two scenarios of SAGD process were simulated. The oil production rates can be reduced due to the frictional pressure drop in the injection well, which is a function of the fluid density and viscosity, tubing and casing diameters, flowrate and the well length.

The heat-exchanger effect plays a role in modifying the steam injection along the horizontal well. These factors have to be considered for accurate prediction of SAGD Process. Further testing of this numerical model will be performed using field data.

CONCLUSIONS

1. This paper presents a coupled reservoir and well model in which the equations are solved simultaneously using Newton's method.
2. Numerical predictions show that the frictional pressure drop affects the performance of the process. By ignoring the frictional pressure drop in the tubing one would overestimate oil production rates. The frictional pressure drop in the annulus caused uneven fluid injection/production along the wells, and reduced the thermal efficiency.
3. The heat transfer between tubing and annulus flows affects the shape of the swept zone in the reservoir.
4. Both the frictional pressure drop and the heat-exchanger effect do not seem to affect the ultimate oil recovery of the SAGD process.

ACKNOWLEDGEMENT

This research is supported by the Alberta Oil Sands Technology and Research Authority (AOSTRA).

NOMENCLATURE

area	perpendicular to flow in well
e	internal energy
g	gravity acceleration
h_j	enthalpy of phase j
I_{we}	well injectivity
K	thermal conductivity of rock
k_{rj}	relative permeability of phase j
m_i	global molar density of component i
p	pressure
Δp_f	pressure frictional drop
q_{ar}	energy transfer by conduction between the annulus and the reservoir rock
q_{at}	energy transfer between annulus flow and tubing flow
q_j	volumetric flowrate of phase j
q_{loss}	heat loss by conduction to cap rocks
r_o	drainage radius
r_w	well radius
S_j	saturation of phase j in reservoir
t	time
T	temperature
T_a	temperature of annulus fluid transmissibility for heat conduction through rock matrix
T_j	transmissibility of phase j
T_t	temperature of tubing fluid overall heat transfer coefficient between annulus flow and tubing flow
U_{at}	overall heat transfer coefficient between annulus flow and tubing flow
u_j	in situ velocity of phase j in well
V	block volume
x	distance in x-direction
y_i	gas-phase mole fraction of component i
α_j	in situ volume fraction of phase j in well
δ	finite difference operator in time
Δ	finite difference operator in space
θ	angle of inclination of the well to the horizontal
λ_j	mobility of phase j
μ_j	viscosity of phase j
ρ_j	molar density of phase j
ϕ	pore volume
ψ_j	potential of phase j

Subscripts

g	gas
i	component identification, i = w,o
j	phase identification, j = o, g, w
o	oil
r	rock
w	water or well

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CONFORMANCE IMPROVEMENT BY USING HIGH TEMPERATURE FOAMS AND GELS

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ABSTRACT

The use of foams to divert the steam from the swept zone has been extensively tested both in the laboratory and the field. On the other hand, gels for plugging unproductive zones have mostly been considered for conventional or relatively low temperature applications. The objectives of this study were the development of strategies for improving the long-distance propagation of foam in the reservoir and evaluation of gels for near-well applications in thermal recovery operations.

The major limitations to the growth of the foam zone include the inefficiencies in foam generation and poor bubble transport. Flow experiments were carried out in sand packs at steamflood conditions to develop strategies for improving foam generation by a pre-foam reduction of residual saturation in the swept zone. The results showed that the pre-foam concept could be used with small slugs of low interfacial tension chemical or solvents to substantially improve the rate of foam propagation. Studies to determine the propagation behavior once foam is generated showed that bubble transport is sensitive to oil saturation but relatively insensitive to injected fluid velocities and liquid volume fraction.

Laboratory experiments were also conducted to test gel performance in porous media over the temperature range 100–300°C. Although the gel strength diminished at high temperatures, significant reductions of steam mobility were still observed at 300°C. Gels in porous media were shown to withstand moderate pressure gradients for extended periods of time at elevated temperatures. The advantage and disadvantage of foam and gel applications at elevated temperatures will be discussed.

INTRODUCTION

Steam injection is the most popular method used for the recovery of heavy oil. However, factors such as steam-channeling, gravity segregation and reservoir heterogeneities often result in poor contact of the pay zone by the injected steam, leading to low recoveries. One method of conformance control which has received considerable attention is the use of surfactant foams, which act by reducing steam mobility, particularly in zones of low oil saturation. Numerous lab and technically successful field studies using steam foams have been reported.[1–3] However, foams do suffer from some disadvantages; surfactant must be continually injected to maintain the foam, and foam stability is sensitive to the presence of oil, clays and divalent ions in the reservoir.

Gels are a complimentary means of conformance control which are generally more suited to near-well applications. One advantage of gels is that once in place, they would not require continued injection. Also, they are expected to be less sensitive to reservoir conditions than foams. However, most of the work on conformance control with gels which has been reported to date has been concerned with low temperature applications in gas or conventional oil reservoirs, because the gel formulations available were not stable at high temperatures. Recently, commercial formulations have been developed which are claimed to be stable at the high temperatures required for steam-based heavy oil recovery processes.[4–8]

In the work reported here, strategies to overcome the inefficiencies in foam generation in the presence of oil by pre-foam injection of chemicals were developed, and the dependence of foam propagation on factors such as residual oil saturation, fluid velocities and liquid volume fraction was examined in sandpacks. Laboratory experiments were also conducted to assess gel performance in porous media as a function of temperature, imposed pressure drop and residual oil saturation.

EXPERIMENTAL

Materials

Cold Lake bitumen was obtained from the Oil Sands Sample Bank of the Alberta Research Council. 140/200 mesh sand (gel studies) and –200 mesh sand (foam studies) were sieved from Ottawa sand. Chevron SD1020 and LTS-18 were obtained from Chevron and Shell, respectively. Phenoformaldehyde gel C302 was obtained from Borden Chemical Co. NaCI and $CaCl_2$ were purchased from Fisher. Deionized water was used in all experiments.

Foam Studies

A schematic diagram of the apparatus used for the foam tests is shown in Figure 1. The jacketed cell (2.5 cm ID and 60 cm long) was dry-packed with sand and flushed with CO_2 gas to remove air prior to saturation with degassed water. The absolute permeability of packs prepared in this manner was about 2 darcy. A residual oil saturation in the pack was produced by first flooding with 1.5 pore volumes (PV) of oil, followed by extensive flooding with steam at a back pressure of 0.7 MPa. The average residual saturation was determined by analysis of produce fluids. Pressure drops along the core were monitored by Rosemount pressure transducers, and temperatures of the injected fluids and along the core were monitored by thermocouples. In all experiments, the production temperature was maintained at about 180°C. At the end of each run, the oil was removed by flushing with toluene followed by isopropyl alcohol. Finally, several PV of water and were flowed through the core, the pack was evacuated to dryness, and the flushing with CO_2 repeated to prepare the pack for the next run.

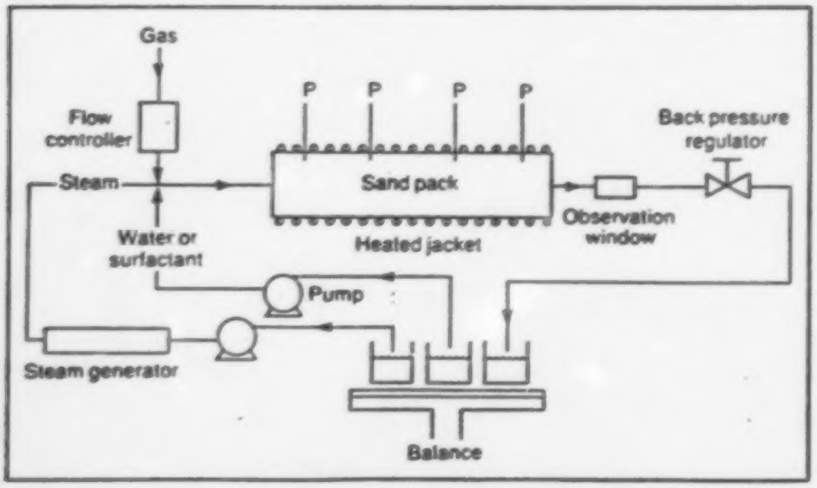

Figure 1. Schematic of the sandpack apparatus for steam-foam experiments.

Gel Studies

A schematic of the apparatus used for the gel studies is shown in Figure 2. The flow tubes (0.94 cm ID and 21 cm long) were packed with sand and mounted inside an oven. Permeability of the packs was about 4 darcy. Pressure drops across each tube were monitored by Rosemount pressure transducers. Gel was placed in the tubes by first flushing the injection line with gel solution and then slowly injecting a measured volume of gel solution into the pack. Following this, the injection line was flushed with water, and the gel slug was pushed a short distance into the pack. The apparatus was then left overnight at the desired curing temperature to allow the gel to set. After the gel had set, the oven was adjusted to the desired run temperature, water injection was started, and behaviour of the gel plug was monitored. The apparatus was either operated in a constant flow mode, in which pressure drops were monitored, or in a constant pressure drop mode, in which pressure drop was maintained at a set value and the flow rate to maintain this pressure drop was monitored. For the runs using oil, a residual saturation was produced as described above.

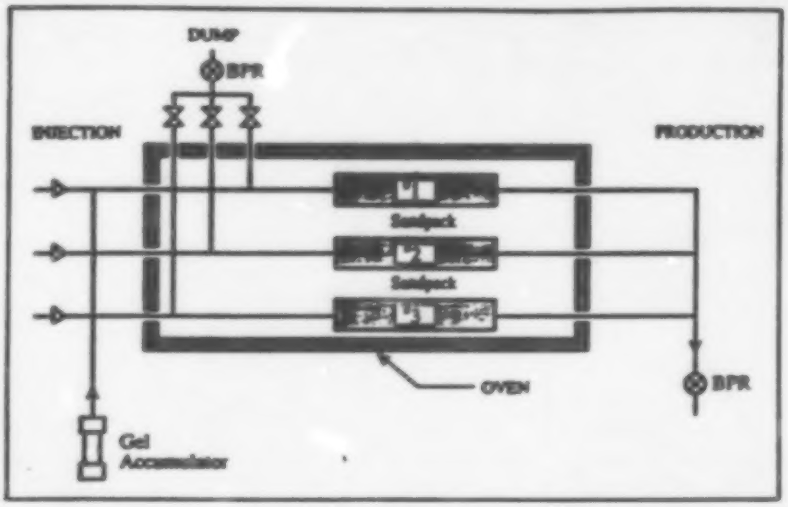

Figure 2. Schematic of the sandpack apparatus for gel experiments.

RESULTS AND DISCUSSION

Effect of Oil

The presence of residual oil saturation in zones requiring mobility control application is known to have a serious detrimental effect on foam formation.[9–10] Of importance is that even under conditions where foam is formed, the rate of propagation is substantially curtailed by the presence of oil (see below).

In contrast to the strong influence of oil on the flow properties of foam, there appears to be little or no effect on the setting and blocking performance of the phenoformaldehyde gel. This is shown in Figure 3 where the ratio of the effective permeability to hot water at 200°C after gelation (gelation time 19 h at 100°C) to that before gelation is plotted against run time for the case of clean sand and sand at residual oil saturation (S_{or}). The effectiveness of the gel is seen in its ability to reduce permeability by more than three orders of magnitude when effective gel placement is achieved. The difference between the oil-free and the residual oil case is not considered significant and is within the range of repeatability. For the pack at S_{or}, the initial increase in permeability ratio is thought to reflect the mobilization and movement of the residual oil as a consequence of the high pressure gradient across the gel plug. It is significant that under these conditions, the gel plug remains stable throughout the duration of the experiment in both runs.

Pre-Foam Slug Technology

Gel stability in the presence of oil provides a distinct advantage over the application of foam. However, gel does not possess the self-correcting flow properties[1] of foam nor the cost advantages per volume of treatment. In order to make reservoir application of foam more effective, new technologies are needed to compensate for bubble sensitivity to oil. The development of more oil-tolerant commercial surfactant,[11] along with improved injection strategy, has considerably ameliorated successful reservoir application. The strategy developed in our laboratory involves injection of a pre-foam slug to mobilize residual oil and allow

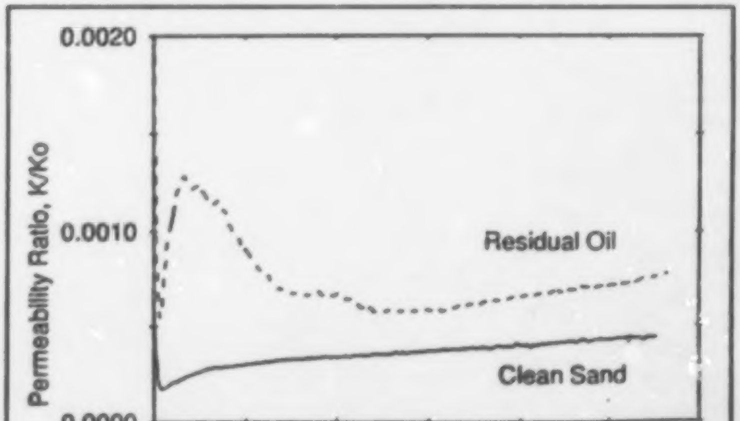

Figure 3. Effect of residual oil on the stability of a gel plug at 200°C.

for rapid foam formation. As an example, Figure 4 compares three steam-foam experiments in 2 darcy packs containing Cold Lake bitumen which have been steamflooded to S_{or}. In the absence of a pre-foam slug, the foam has taken about 10 pore volumes (PV) to generate, even with an oil-tolerant surfactant (Chaser SD1020) being used. Injection of a 0.25 PV slug of either diesel solvent or interfacial-tension(IFT)-reducing-surfactant has considerably hastened the evolution of the foam. The diesel solvent is miscible with the residual oil, reducing its viscosity and hence making it more amenable to mobilization by the steam. The low IFT slug was designed to mobilize the residual oil by reducing oil/water interfacial tensions below 10^{-2} mN/m at run temperatures.

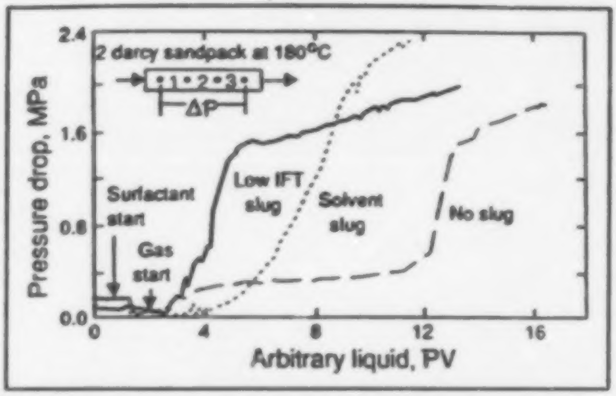

Figure 4. The effect of pre-foam slug injected prior to foam formation, on the rate of foam propagation.

Flow Resistance of Foams and Gels

Foam flows in the reservoir by "making" and "breaking" processes. Because of its dispersed nature, foam exhibits low flow mobilities depending on texture (bubble size and distribution) in relation to the imposed injection and reservoir conditions.[12] In order to perform successfully, the foam must withstand a vast range of conditions and still maintain its integrity and flow resistance properties. For a given surfactant and reservoir type, therefore, it is important to consider a range of gas and liquid velocities and liquid volume fraction (LVF).

Figure 5 shows the effect of gas velocity at constant liquid velocity on the relative permeability to gas (k_{rg}) for a 2 darcy pack containing residual oil after steamflooding (15 PV) at 180°C. The k_{rg} is a measure of foam flow resistance; the higher the k_{rg} the lower the foam resistance. It is apparent that the foam flow resistance decreases with increasing gas velocity. Because the liquid velocity has been held constant, the LVF of the injected foam (given in parenthesis) is changing. As the LVF decreases the foam is becoming drier and its resistance to flow declines.

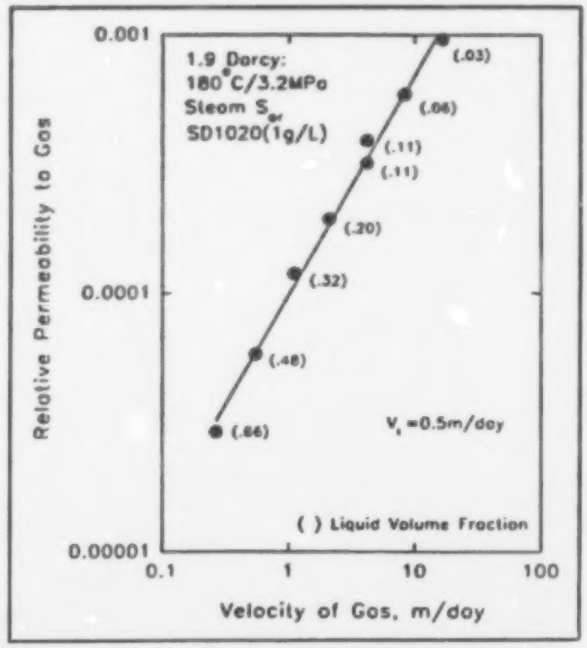

Figure 5. Effect of gas velocity on the foam flow resistance.

Figure 6 shows the reverse case where the gas is held constant and the liquid velocity is changed. The resistance of the foam (decreasing k_{rg}) is seen to increase with increasing liquid velocity. As before, the wetter the foam (higher LVF), the more resistant it is to flow. When k_{rg} is plotted against LVF (not shown), it is apparent that the foam flow resistance is not a unique function of LVF. This is in agreement with the work of Persoff et al.[12]

Figure 7 shows the effect of simultaneous change of gas and liquid velocity keeping the LVF constant (0.15) where k_{rg} is plotted against fluid velocity at two

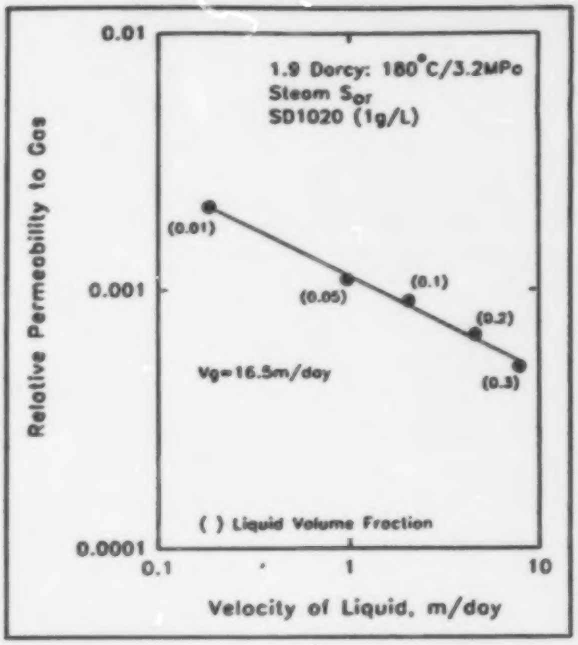

Figure 6. Effect of liquid velocity on the foam flow resistance.

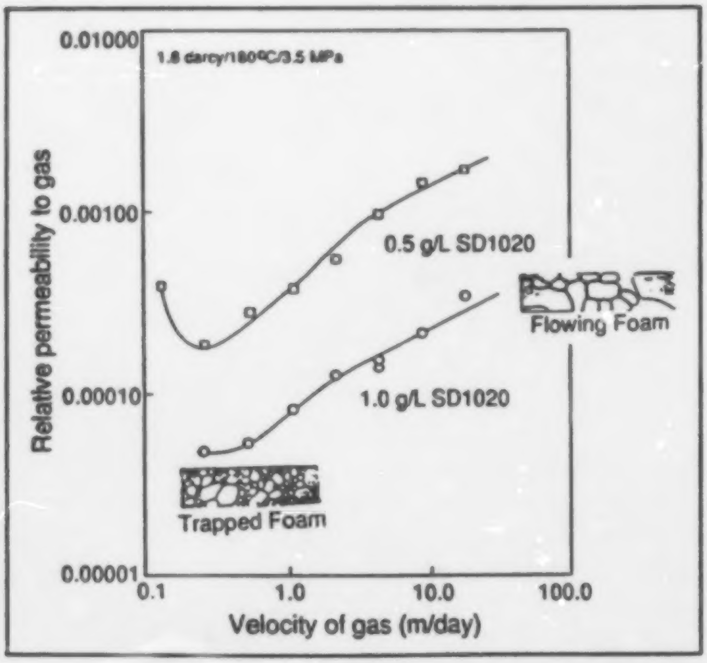

Figure 7. Effect surfactant concentration and fluid velocity at constant LVF, on the foam flow resistance.

surfactant concentrations. At high velocities, there is a shear thinning effect which we associate with flowing foam"; whereas, at low velocities the foam is much more resistant to flow with a tendency towards being a "trapped foam". As depicted in the photographs included in Figure 7, the difference between the "flowing" and "trapped foams is in the texture. The higher the surfactant concentration, the greater the foam resistance at all flow rates. Thus, if desired, the surfactant concentration can be used to compensate for the effect of fluid velocity. It is also clear that foams can withstand drastic changes in fluid velocity, and their velocity dependence is exactly what is required in the reservoir; that is, relatively low resistance near the injection well, where velocities are high, and higher resistance further into the reservoir.

In contrast to the flowing nature of foams in porous media, gels display more permanent blocking behavior. In fact, the mobility reduction capability of gels is of the same order as that observed for trapped" foam. Figure 8 shows the effect of imposed pressure drop on the resistance of a gel plug to hot-water injection at 200°C. In the first 25 h, the pressure drop was changed step-wise from 15 to 90 and back to 15 kPa with little or no effect on the permeability ratio. The gradual decay in the resistance of the gel (from K/K_0 of 0.01 to 0.02) was probably due to thermal degradation(see below). Above a pressure drop of about 120 kPa, the gel strength began to decay rapidly, suggesting significant shear degradation. From a reservoir perspective, the placement of the gels in terms of mechanical stress and temperatures that they are likely to encounter is crucial.

Temperature Stability

The temperature stability of surfactants with sulfonate moieties, used in steam-foam applications, is well understood.[13,14] The degradation mechanism involves hydrolysis which is autocatalized by the presence of acid. At neutral and basic pH conditions. sulfonate surfactants are stable for periods of months even at temperatures above 250°C.

In contrast to foams, little is known about the thermal stability and mechanisms of degradation of phenoformaldehyde gels in aqueous environments. Figure 9 shows the effect of temperature (100° to 300°C) on the "blocking" performance of a pre-set gel to hot water flowing at a constant flow rate of 4 cm^3/h. At 100°C the gel appears to be indefinitely stable. At 250°C, the gel shows a gradual decrease in flow resistance with time, whereas at 300°C, there is an initial rapid decline in resistance, followed by relatively constant behavior. Post-run examination of sand packs from a number of these experiments has shown that above about 250°C, the gel breaks down to small particles which act like fines to plug pore throats. The oscillatory nature of the 300°C plot of Figure 9 is a reflection of this behavior. Below about 250°C it appears that the bond breaking mechanism of the gel degradation is considerably curtailed; on the time scale of these experiments, the gel consists of a series of large ganglia, each of which covers several pores.

The effect of temperature on K/K_0, determined after 28 h of hot water injection, is plotted in Figure 10. Figure 11 represents an a Arrhenius plot of the same data. The linearity of the $\ln(K/K_0)$ vs 1/T plot allows us to calculate an apparent activation energy of about 40 kJ/mole. This relatively low value suggests a degradation mechanism other than simple bond breaking, possibly hydrolysis.

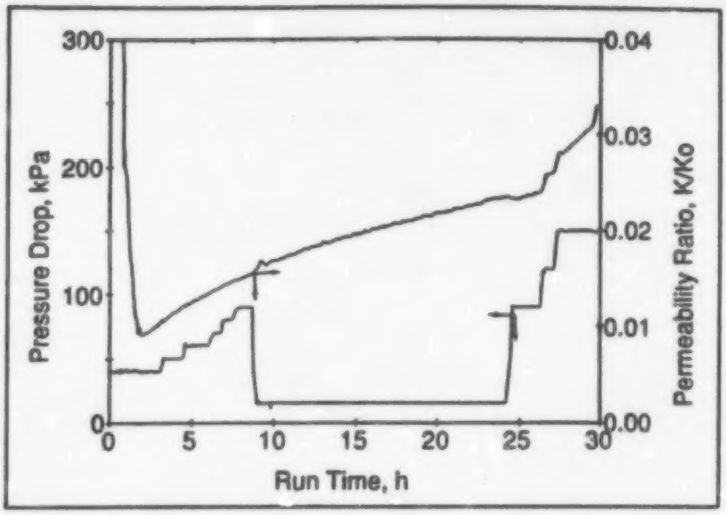

Figure 8. Dependence of gel stability on imposed pressure drop at 200°C.

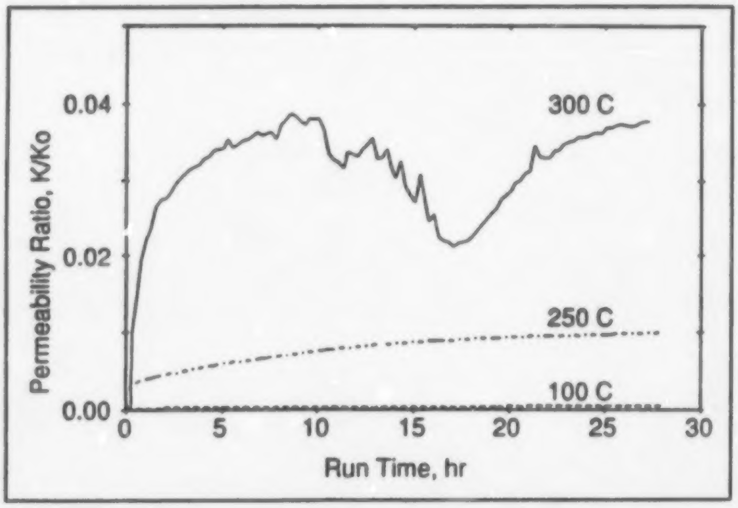

Figure 9. Effect of temperature on the evolution of permeability ratio.

Gel Stabilized Foams

Under certain reservoir conditions, foams have advantages over gels and vice versa. To combine the strengths of both foams and gels may provide improved technology for reservoir applications. In this regard, we have examined the possibility of creating more permanent foams which, ideally, once formed would require no surfactant replenishment. This may be achieved by gelling the aqueous fluid in the lamellae separating the gas bubbles of the foam. Preliminary experiments suggest that the concept is sound and that gel stabilized foams can provide a significant increase in foam lifetime. This work is undergoing patent protection at the present time.

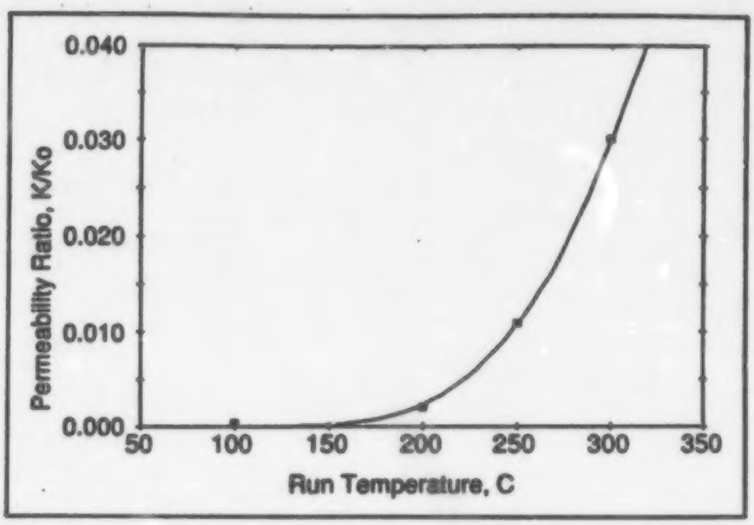

Figure 10. Dependence of permeability ratio (at 28 h run time) on temperature.

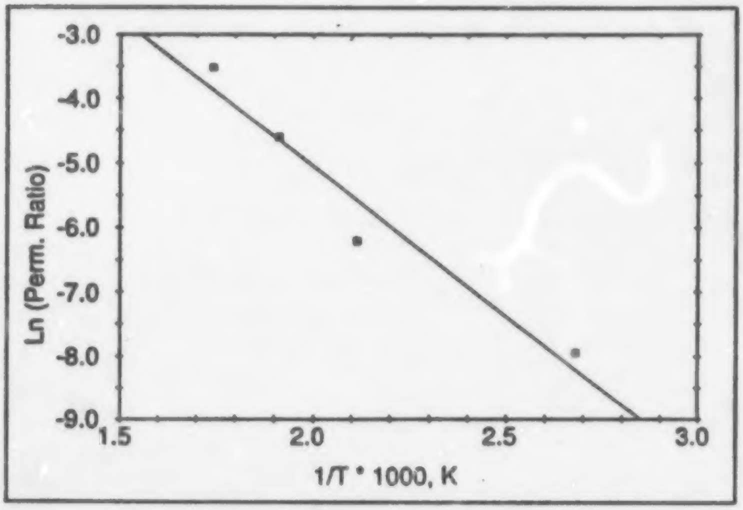

Figure 11. Arrhenius plot of permeability ratio.

CONCLUSIONS

Foams and gels are complimentary chemicals which can be used for conformance control applications in steam based processes. Although the gel strength is diminished at high temperatures, significant reductions of steam mobility were still observed at 300°C.

A major advantage of gels is that they are relatively insensitive to reservoir conditions and are unaffected by, for example, the presence of oil. A major concern with steam foam processes is the sensitivity of the bubbles, and the surfactant used to stabilize them, to the presence of oil, divalent ions and clays. Injection strategies based on the use of a pre-foam slug were developed and used to ameliorate the problem of oil sensitivity and thereby improve the rate and extent of propagation of foams in porous media.

Foams, once generated, can withstand the drastic changes in fractional flow rates and fluid velocities typically encountered during many injection-production scenarios. This combined with relatively low costs per volume of treatment makes foams amenable to long distance transport in the reservoir. Gels are more sensitive to pressure gradients above a certain threshold and will undergo shear degradation.

ACKNOWLEDGEMENTS

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THE STUDIES OF INTERFACIAL TENSION AND EMULSION CHARACTERISTICS OF HEAVY OIL/HOT CAUSTIC SOLUTION SYSTEMS

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ABSTRACT

In respect to improving heavy oil recovery, the interfacial tension (IFT) and emulsion characteristics of heavy oil and caustic solution are the two important parameters of the caustic waterflooding process. For example, the IFT between the two fluids reduced by two magnitude, the capillary number would increase by two orders, and the oil recovery could be substantially enhanced. This is because in-situ emulsion at certain conditions in the reservoir could improve oil displacement, collect the dispersed oil, and increase volumetrical sweep efficiency.

In this paper, the IFT and emulsion characteristics of three caustic solutions with heavy oil are reported. The caustics used for this study were sodium carbonate, sodium hydroxide, and sodium silicates; the heavy oil was obtained from the Jinglou oil field. The results of this research indicate that at a certain range of temperature and caustic concentration, the said IFT could be reduced to 10 E-2 (mN/m). But the potency of IFT reduction in the heavy oil-sodium carbonate system was affected by formation brine, when it was greater than 50% by volume. However, this brine had no influence on that in the heavy oil-sodium hydroxide and heavy oil-sodium silicates systems.

The viscosity and phase changes in emulsions exhibited a very complicated relationship with the system temperature, oil-water mixing ratio, brine salinity, and caustic concentration. In the fresh water system, the viscosity of oil/water emulsion decreased as water volume increased; the oil/water mixing ratio also controlled the changes of viscosity with temperature. In the formation brine system, no effect was observed on the emulsion's viscosity at the low oil/water mixing ratios. But at the higher ratios, the emulsion's viscosity increased, and the tendency of phase conversion seemed to be affected by caustic strength. It was interesting to find that sodium carbonate possessed such active and flexible characteristics in those tests we observed.

INTRODUCTION

The heavy crudes normally contain certain organic acids. When these transact with caustic solutions, the products surfactants would play certain roles reducing the oil/water interfacial tension and emulsifying the fluids. If this happens in waterflooding a heavy oil reservoir, such emulsion would help oil displacement and enhance oil recovery. Starting from early this century, laboratory studies[1–4] have been trying caustic soda as a chemical additive for this purpose. The following are brief summaries of the investigations:

- 1974: Ehrlich et al.[5] pointed out that if oil-water interfacial tension is below a critical value in the reservoirs, caustic flooding can improve oil recovery by mechanisms of emulsification and entrainment.
- 1925: Nutting[6] utilized sodium hydroxide solution in an experimental waterflooding of Torpedo sandstone. The conclusion was that the increase of oil recovery was attributed to the IFT

reduction between oil and water. This was done either by chemical reaction or by absorption of the alkaline solution with silica at the interface.

- 1975: Jennings[7] reported the results of a study of caustic solution crude oil interfacial tension measurements on 164 crude oils from 78 fields. Based on this data, the surface activity of oil against caustic solution was correlated with the acid number, oil gravity, and viscosity. In his tests of the interfacially active samples, 90% of them reached the maximum measurable surface activity at the caustic concentration of nearing 0.1% by weight.
- 1978: Bansal et al.[8] stated that from electrophoretic mobility and IFT measurements of crude oil/caustic systems, the minimum in the IFT corresponds to the maximum electrophoretic mobility. The said minimum case was explained on the basis of surface charge density at the crude oil/caustic interface. They also introduced a simple optical absorbance test to determine the optimum caustic concentration necessary to produce the minimum IFT and the maximum electrophoretic mobility.
- 1953: Dunning et al.[9] claimed that the improved oil recovery by adding sodium hydroxide for waterflood was the result of the surfactant produced by the crude and caustic reaction. In this system, the surfactant replaced the interfacially active asphaltic aggregates, which is responsible for inhibiting oil displacement.
- 1974: Cooke et al.[10] reported that if the composition of the crude is favourable, some crude oils and porous media systems can be converted from a water wet to an oil wet state and oil/water IFT can be simultaneously lowered to very low values by the right combination of caustic and salt.

The in-situ generation of emulsion in the pore spaces of the reservoir rock was determined by the injection of caustic solution, its entrainment into a continuous flowing phase, and its entrapment by pore throats due to several different mechanisms. These have been suggested as the basis of caustic flooding oil reservoirs.

- 1942: Subkow[11] patented the injection of aqueous emulsifying agents containing sodium hydroxide for recovering heavy oil or bitumen.
- 1974: Jennings et al.[12] presented an analysis of a variety of laboratory data, that indicated that caustic waterflooding can significantly increase oil recovery obtained before water breakthrough. The mechanism of this involves in-situ generation of oil in water emulsions that tend to plug growing water fingers and channels, diverting flow to give improved volumetric coverage or sweep efficiency.
- 1976: Johnson[13] reviewed the status of caustic and emulsion methods for enhanced oil recovery. The four fundamentally different mechanisms along with many process variations, by which caustic can operate, were discussed.
- 1979: Alvarado et al.[14] studied the rheological behavior of oil-in-water macroemulsions by using capillary tubes in which the oil concentrations varied from 10 to 70% by volume. For the ranges (10^3 to 10^4 per second) of shear rate investigated, the oil in water macroemulsions having oil concentrations less than 50% acted like Newtonian fluids, while those greater than 50% behaved like pseudoplastic fluids.
- Flock et al.[15] reported that emulsion viscosity can be related with shear rate, temperature, and disperse phase concentration. They indicated that the rheology of oil-in-water emulsions prepared by using the Alberta heavy crudes at room temperature behaved like Newtonian fluids when the disperse phase concentration was less than 15% and the testing shear rates ranged between 50 to 1,000 per second. While the oil concentration was greater than 15% with the same testing shear rates, the emulsions behaved like non-Newtonian fluids.

In this paper, we report the laboratory results of the interfacial tension and emulsion characteristics from the study of the Jinglou (Zero zone) heavy crude with a high acid number. This was a part of the studies using hot caustic flooding heavy oil reservoirs for enhanced oil recovery.

INTERFACIAL TENSION (HEAVY OIL CAUSTIC SOLUTIONS)

The caustic solutions injected into reservoirs would act with organic acids in the crudes and create surfactants, which will then lower the IFT between oil and water, and emulsify these fluids. The objective of this study was to investigate the minimum IFT in the said system related to the testing temperatures, caustic concentrations, and the amount of formation water involved.

Experimental Method

The spinning-drop tensiometer (SITE02 model) was used to measure the IFTs on caustic solutions and the Jinglou crude. The said oil, obtained from the Jinglou well 101, is characterized by its 0.9565 g/cm^3 of density, 2366 mPa·s of viscosity at 50°C (shear rate of 28.8 per second), 3.13 of acid number, and 1% organic acid. The testing temperature ranged from 35°C to 90°C after five minutes of spinning. The effect of formation water on IFT testing was also determined.

Heavy Oil – Sodium Carbonate Solutions

Figure 1 shows the IFT versus temperature at various Na_2CO_3 concentrations in the distilled water. Within the testing range (0.5 to 3.0 wt% concentration), the lowest IFT of 10 E-2 (mN/M) could be reached at 50°C to 70°C. As the temperature increased, the IFT tended to increase at about one order of magnitude (dotted lines in Figure 1 cover the IFT from 0.01 to 0.1 mN/m).

The effect of IFT reduction could be diminished by adding more formation brine in the distilled water (increasing WF/WD ratio) for testing. At the low ratio, the IFT of 10 E-2 (mN/m) can still be obtained. Figure 2 shows that at the WF/WD ratio of 7:3, the IFT decreased as the caustic concentration increased.

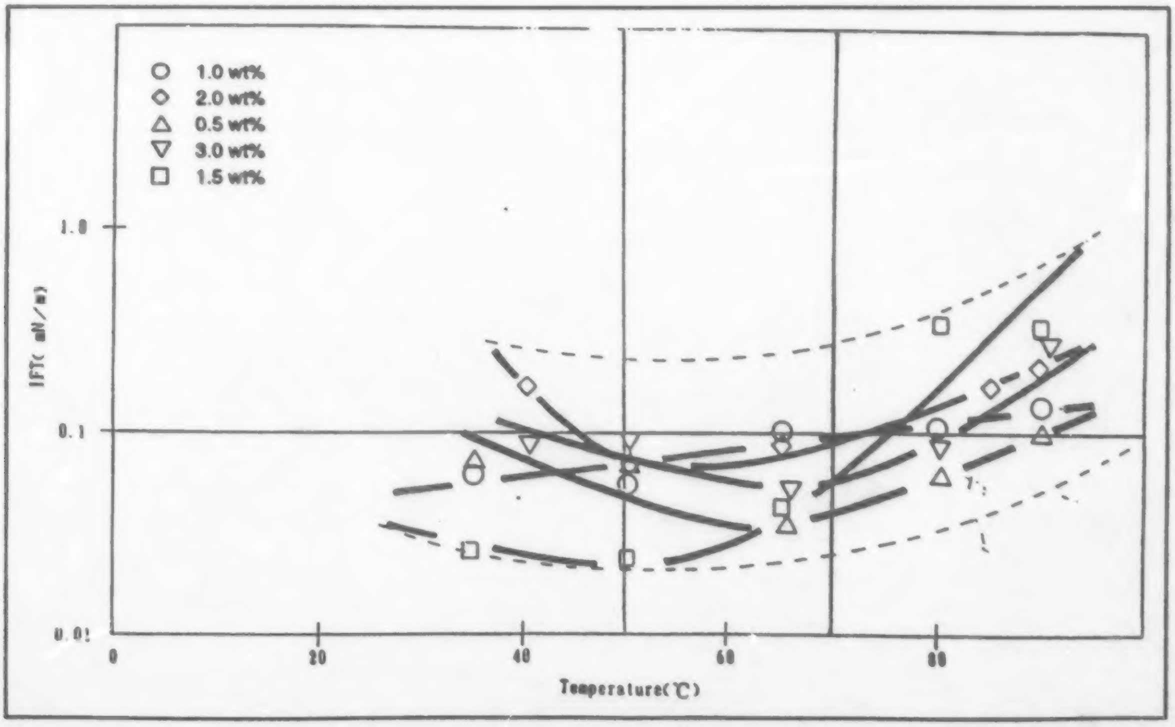


Figure 1. Experimental results showing the variation of interfacial tension with temperature at different Na_2CO_3 concentrations.

When it was greater than 1% by weight, the IFT could drop to 10 E-2 mN/m. Figure 3 shows the test results at the constant caustic concentration of 0.4%. The IFT decreased to 10 E-2 mN/m (covered by dotted lines) at 55°C to 75°C and at W_F:W_D ratio of 5:5. The analysis of formation water is listed in Table 1.

To explain this situation, Jennings[7] demonstrated that calcium chloride in solution suppressed surface activity, and sodium chloride in solution reduced the caustic concentration, which is required to give maximum surface activity. Our study as shown in Figures 2 and 3 proved that the calcium chloride content in the formation water did influence the IFT. Because calcium soaps are very soluble in oil, this seemingly caused the problem. In considering the in-situ movement of the injected caustic solution, which would mix with the formation water at the sweeping front, the W_F:W_D ratio of 5:5 could be quickly

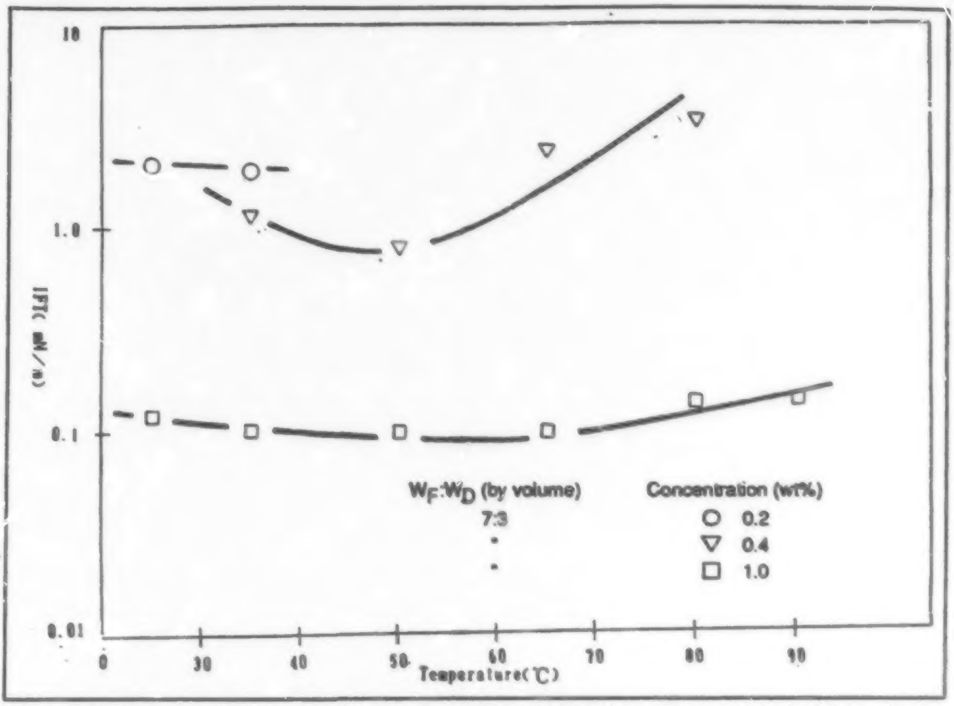


Figure 2. Experimental results showing the effect of formation water on interfacial tension at different Na_2CO_3 concentrations.

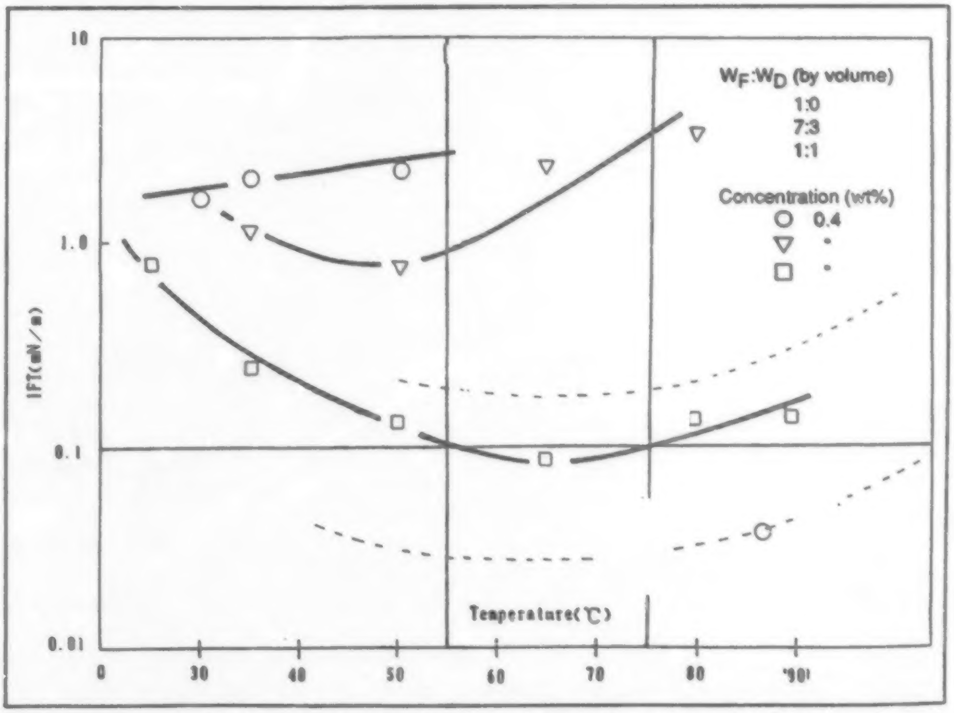


Figure 3. Experimental results showing the effect of formation water on interfacial tension at a Na_2CO_3 concentration.

Table 1. Composition of formation water (mg/L)

K + Na	Ca	Mg	Cl^-	$SO_4^=$	HCO_3^-	$CO_3^=$	Salinity
1406	37	26	1688	40	818	98	4113

reached after a short time of contact. In this case, the IFT as shown in Figures 1 and 2, would stay below the level of 10 E-2mN/m when the caustic concentration is controlled between 0.4% to 1.0% and temperature between 55°C to 70°C.

Heavy Oil – Sodium Hydroxide Solutions

In the Jinglou crude/NaOH solution system, there exhibits the lower IFTs measured in the certain range of temperature and NaOH concentration. Figure 4 shows the IFT curves against various temperatures at NaOH concentration (in distilled water) from 0.15% to 0.5% by weight. It can be observed that the minimum IFT (less than 10 E-2 mN/m) of each curve exists in the temperature between 45°C and 65°C. Within this optimum temperature range, the said lowest IFT existed at the NaOH concentration of about 0.5 wt% (Figure 5). The IFT of Jinglou crude/NaOH solution was slightly affected by the formation water in the tests with NaOH concentration between 0.1 to 1.0 wt% (Figure 6). The data points scattered within the bold lines show a minimum IFT in this graph. Such results indicate that there might be a small amount of calcium soap in the Jinglou crude. From these tests, the most observed IFTs were less than 10 E-2 mN/M, which were measured in the temperature range from 35°C to 65°C and the concentration range from 0.1 to 1.0 wt%. Under the influence of formation water, the lower IFT as mentioned above can still be obtained for NaOH concentration between 0.15 to 0.5 wt% in the temperature range from 45°C to 65°C.

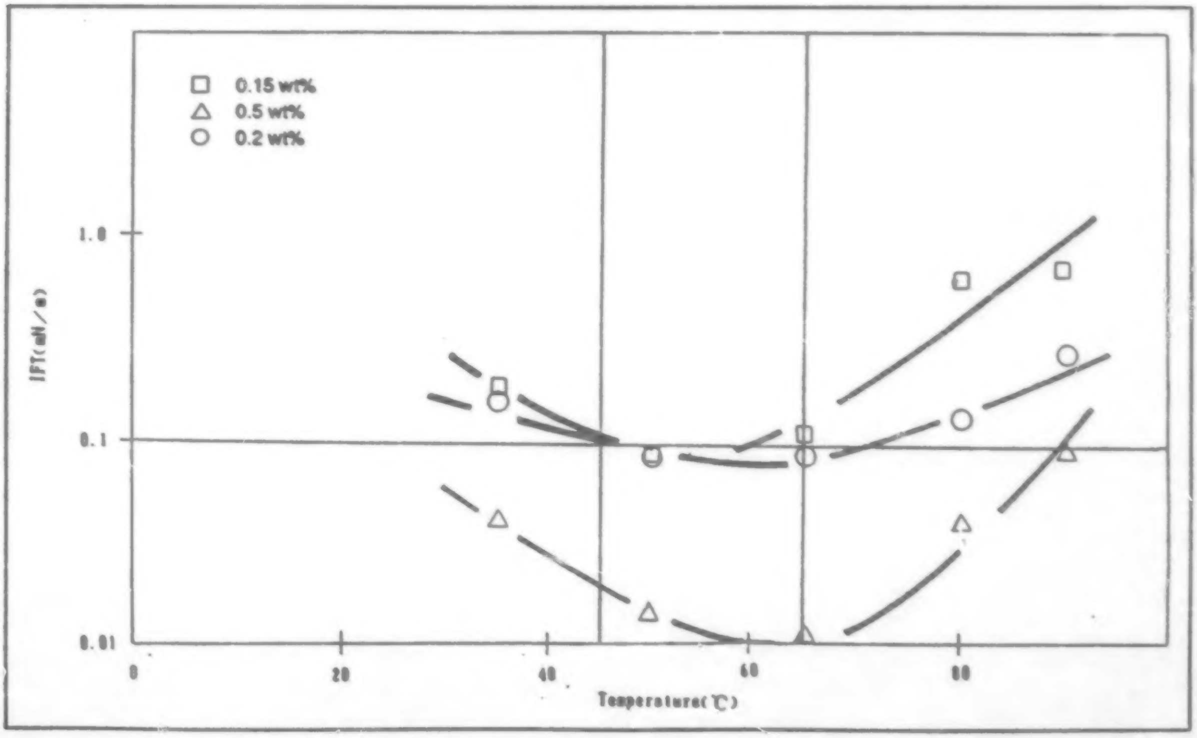


Figure 4. Experimental results showing the variation of interfacial tension with temperature at different NaOH concentrations.

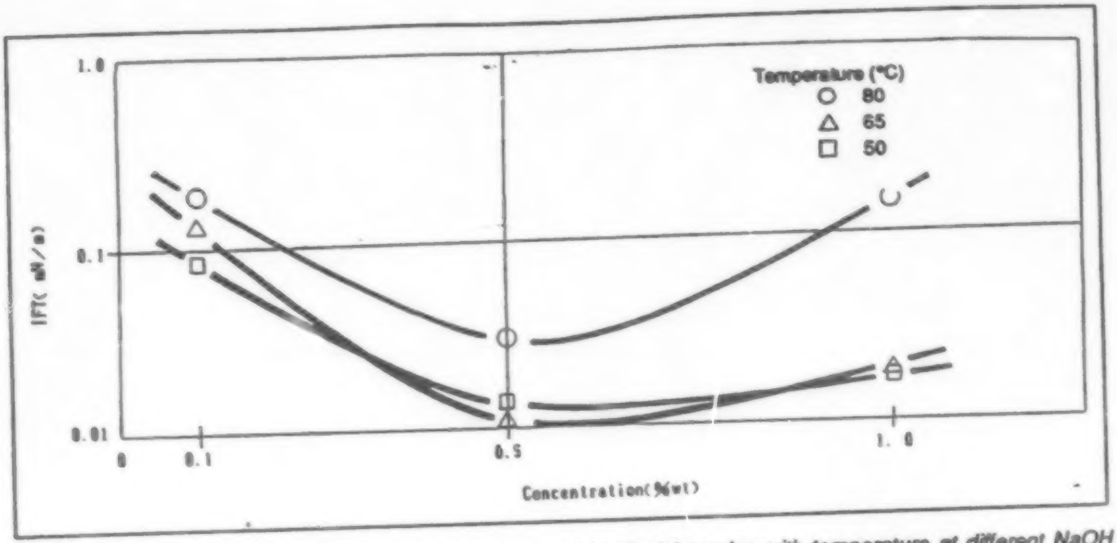


Figure 5. Experimental results showing the variation of interfacial tension with temperature at different NaOH concentration at different temperatures.

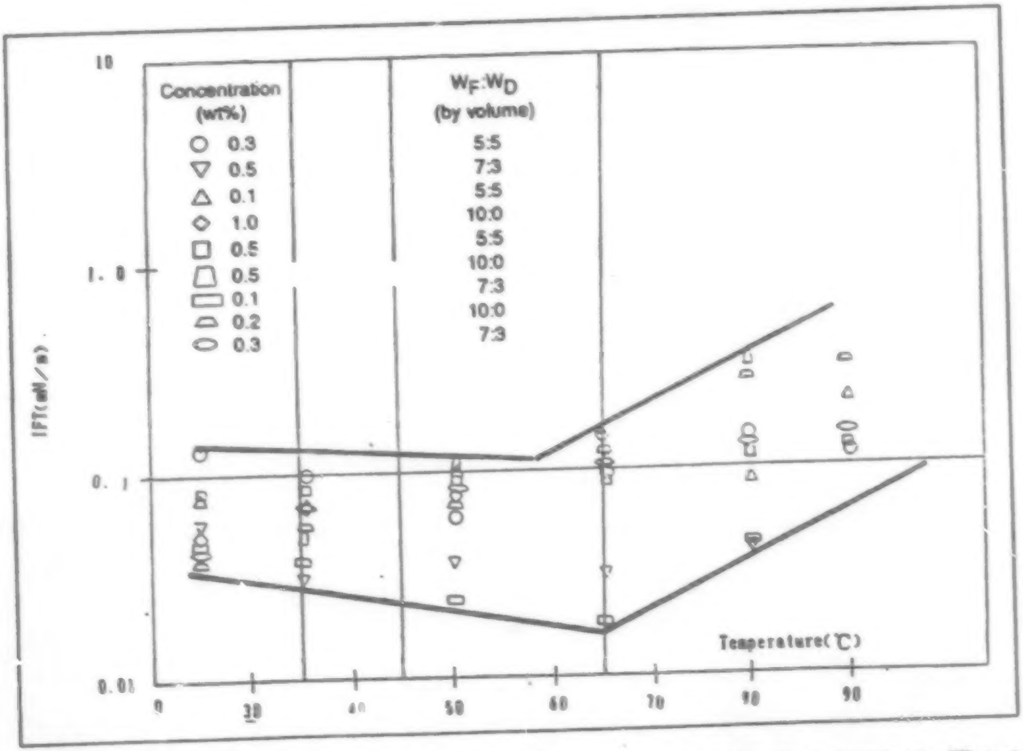


Figure 6. Experimental results showing the effect of formation water on interfacial tension at different NaOH concentrations.

Heavy Oil – Sodium Silicates Solutions

In the Jinglou crude/sodium silicates solutions, the measured IFTs increased as the temperature built up. This can be found in the Na_2SiO_3 solution with concentration of 0.03 wt% to 1.0 wt% in distilled water (Figure 7), and in the Na_4SiO_4 solution prepared with W_F:W_D ratio of 10:0 to 5:5 (Figure 8). From the data plotted in these two figures, the IFTs in most cases were below 10 E-2 mN/m measured at the temperatures from 35°C to 60°C and concentrations from 0.1 to 1.0 wt%. In general, the IFTs were not influenced by the existence of formation water.

A Brief Summary of the IFT Measurements

1. The IFT of the Jinglou crude and three caustic solutions could reach 10 E-2 mN/m in the certain optimum ranges of temperature and caustic concentration (Table 2).
2. When the content of formation brine was higher than 50% by volume, the magnitude of IFT reduction in the oil/Na_2CO_3 system decreased. But the IFTs in the oil/NaOH and oil/sodium silicates systems were influenced only slightly.

CHARACTERISTICS OF EMULSIONS (HEAVY OIL CAUSTIC SOLUTIONS)

The purpose of this study is to measure the viscosity of emulsions, which were created by three groups of caustics with the Jinglou crude at different temperatures, caustic concentration, oil/water ratio, and formation brine content. The results will not only provide the information for field practice and understanding the mechanism of phase conversion, but also contribute to the basic data as inputs for numerical simulation.

Experimental Method

The emulsion of heavy oil and caustic solutions were made both manually and mechanically. The

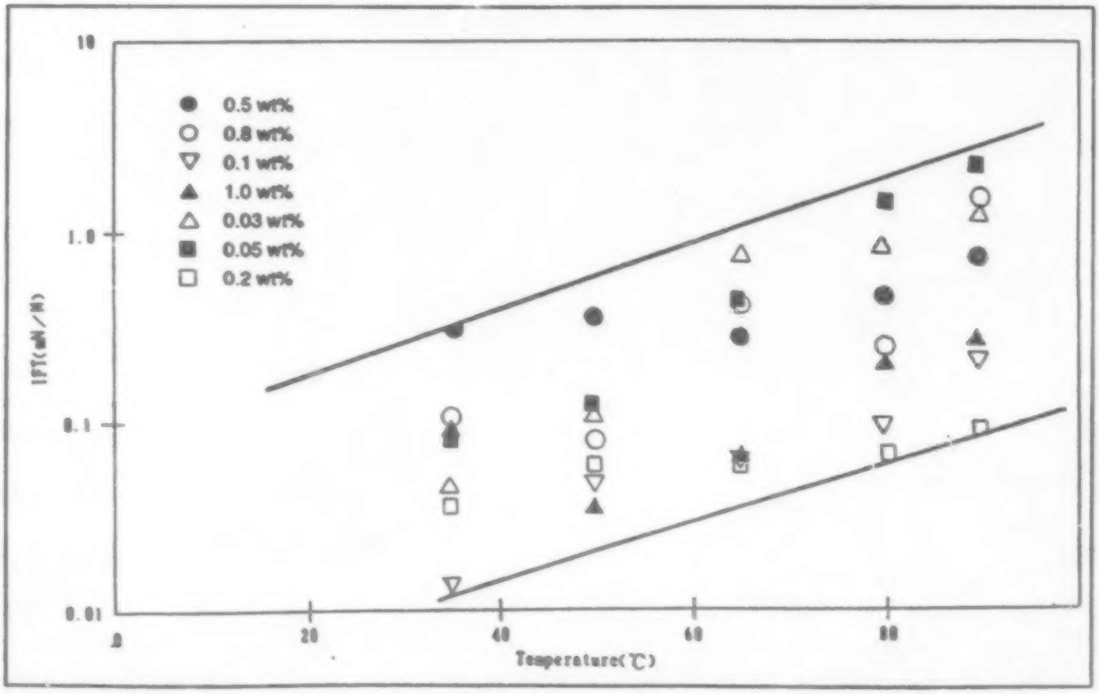


Figure 7. Experimental results showing the variation of interfacial tension with temperature at different Na_2SiO_3 concentration.

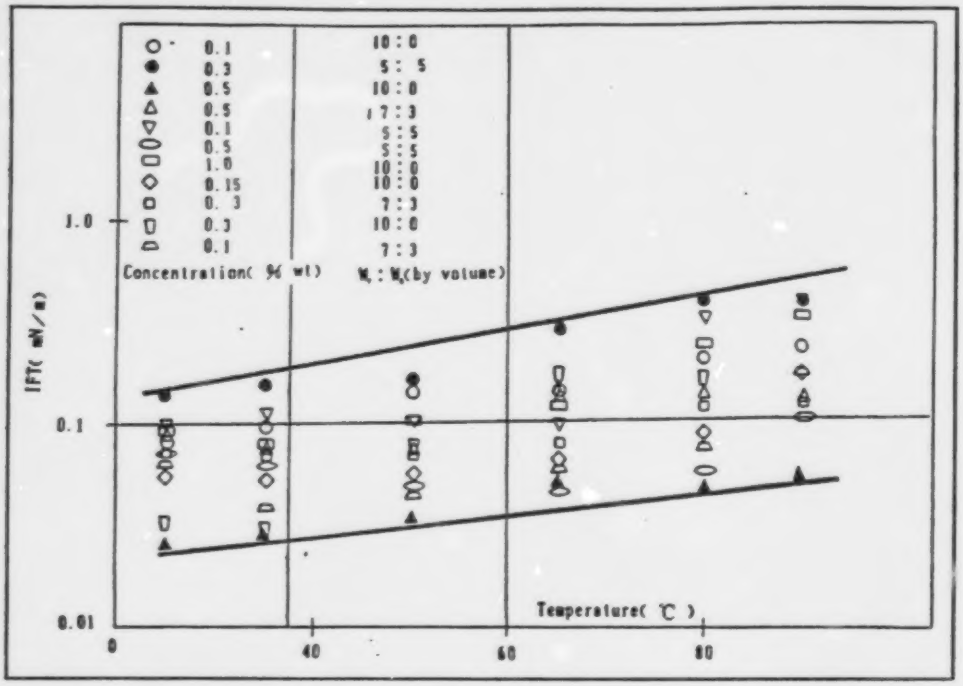


Figure 8. Experimental results showing the effect of formation water on interfacial tension at the different Na_4SiO_4 concentrations.

Table 2. The optimum concentration and temperature range of low IFT (≤10^{-2} orders of magnitude) of three caustics

Caustic	Na_2CO_3	NaOH	Na_2SiO_3
Concentration (wt%)	0.5 to 1.0	0.15 to 0.5	0.1 to 1.0
Temperature (°C)	55 to 70	45 to 55	35 to 60

former approach was to stir the mixtures by hand, and the latter by machine for 15 minutes at 2,000 rpm. The viscosity of the bubbles removed, well-distributed emulsion (after setting for 30 minutes) was measured by the HAAKE-Rotovisco RV12 viscosity meter.

Based on the compatible principle, the emulsion type was determined by using a M3Z Stereomicroscope (magnification-490). This was done through the microscopic observation of the oil-water emulsion. In a simple way knowing the type of created emulsion, two drops of emulsion were put into two beakers filled with either water or kerosene. If the emulsion dispersed in water, indicating that it was oil-in-water type, on the contrary, it must be water-in-oil type. The microstate of emulsion was observed through the photomicrograph, which was taken from the emulsion diluted 10–50 times. The particle-size in emulsion and its distribution were determined by magnifying the picture to 800 times.

Results of Experiment

The effect of oil-water ratio on emulsion's viscosity. Figures 9, 10, and 11 respectively show the changes of emulsion's viscosity (shear rate 1 to 128 per second) with temperatures at different oil-water ratios in the solutions of Na_2CO_3 (0.2 wt%), NaOH (0.5 wt%), and Na_2SiO_3 (0.4 wt%). These indicate that the emulsion's viscosities decreased with the increasing temperature when the oil-water ratio was equal to or less than 5:5. Greater than this, the said viscosities increased with the increasing temperature. The latter observation might be the results of the phase conversion, and more stable condition in this kind of emulsion.

The effect of formation water on emulsion's viscosity. The emulsion's viscosity with temperatures was slightly affected by formation brine at low oil-water ratio (equal to or less than 5:5). Figures 12 through 17 show the said relationship at the oil-water

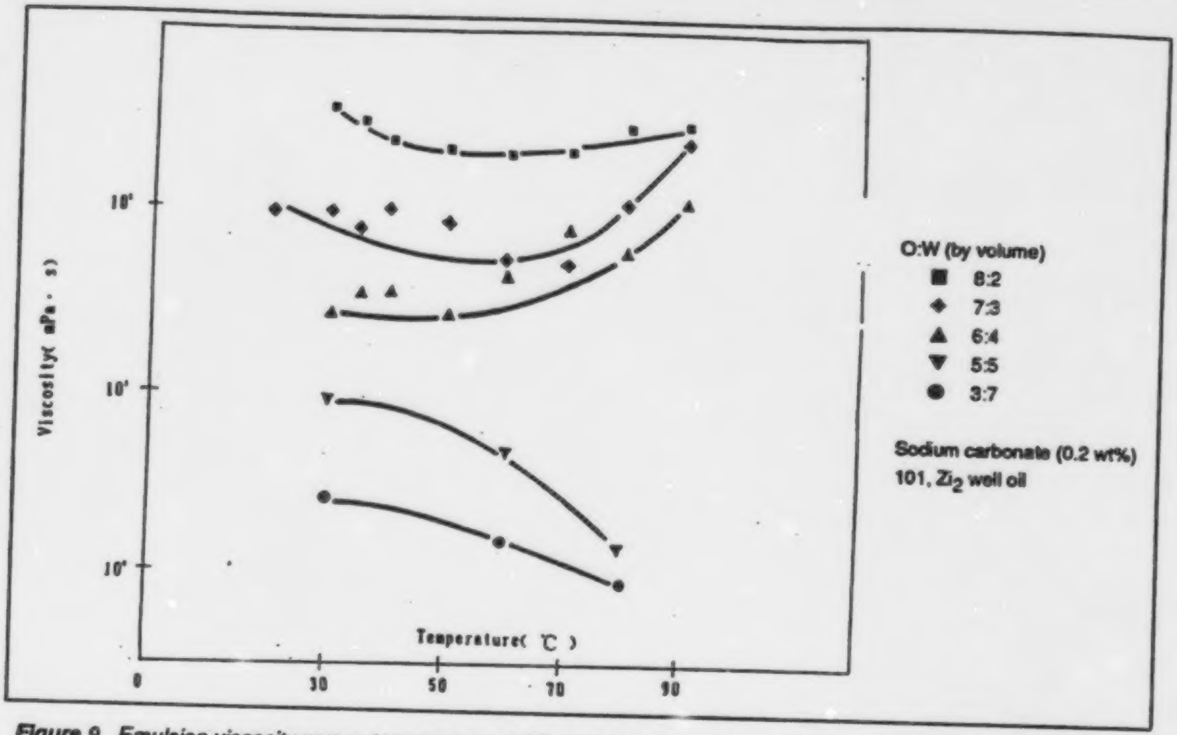


Figure 9. Emulsion viscosity versus temperature at different oil/water ratios (by volume) at a Na_2CO_3 concentration.

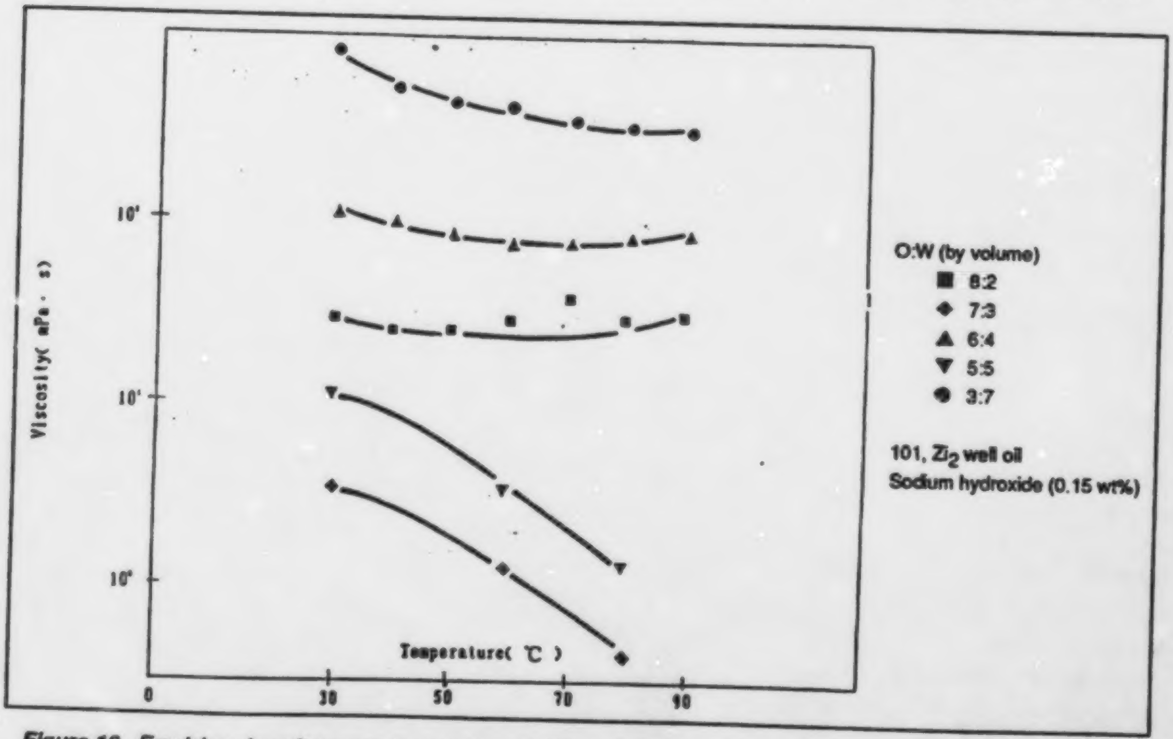


Figure 10. Emulsion viscosity versus temperature at different oil/water ratios (by volume) at a NaOH concentration.

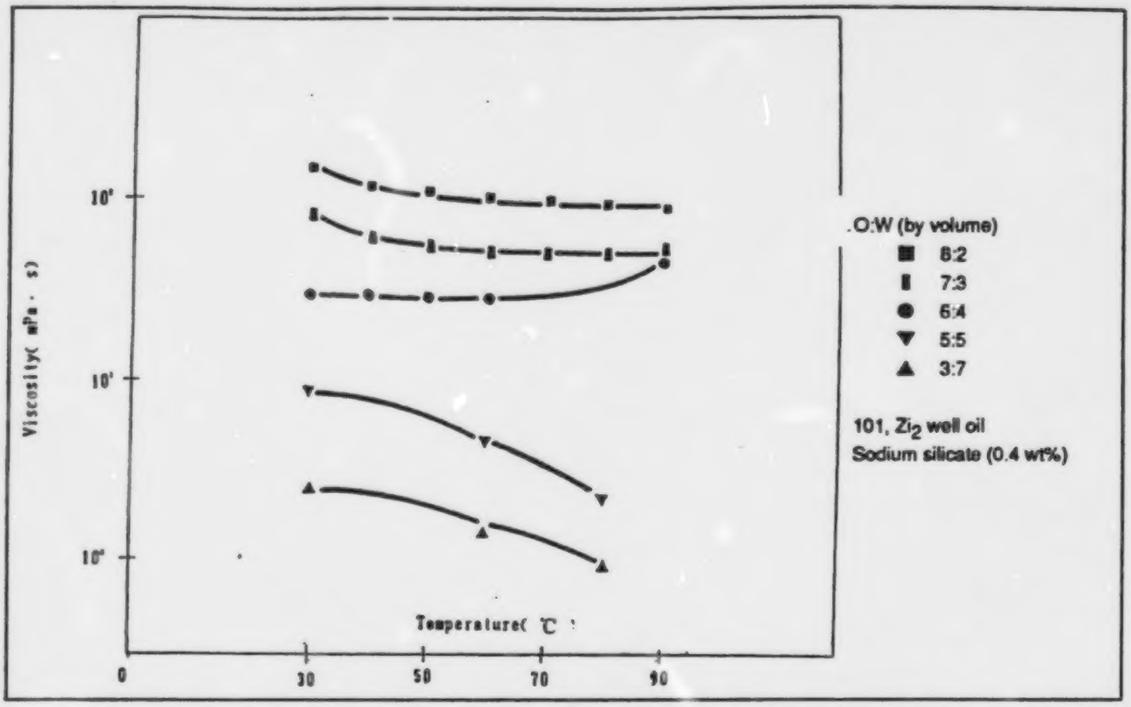


Figure 11. Emulsion viscosity versus temperature at different oil/water ratios (by volume) at a Na_2SiO_3 concentration.

ratios of 3:7 and 5:5 for Na_2CO_3, NaOH, and Na_4SiO_4 in the distilled and formation water, respectively. These tests were performed in the solutions with caustic concentration between 0.1 to 0.6 wt%. The ranges of measured emulsion's viscosity in these solutions (30°C to 80°C) are presented in Table 3.

Factor of influencing phase conversion in emulsions.

a. Caustic concentration effect. The phase conversion in emulsions was dominated by the caustic concentration, rather than by temperature in the fresh water. Figures 18 through 20 show that at a higher oil-water ratio of 7:3 in the Na_2CO_3, NaOH, and Na_2SiO_3 solutions, the emulsion's viscosities in certain caustic concentration were greater than the oil phase viscosity. From the previously mentioned tests (compatibility tests in Figures 21 and 22; microphotographs in Figure 23), these emulsions were not oil-in-water type but water-in-oil type. The range of caustic concentration affecting phase conversion in emulsions are listed in Table 4.

b. Formation water effect. The effect of formation water on phase conversion in the said caustic solutions was different. The phase conversion for Na_2CO_3 emulsion was controlled by formation brine at a higher oil-water ratio of 7:3 (Figure 24). All the observed emulsions were water-in-oil type at the ranges of the testing concentration and temperature in this investigation. However, the phase conversion for NaOH and Na_2SiO_3 emulsions in general were not affected by formation water as shown in Figure 25 and Figure 26. True, formation water slightly influenced the phase conversion for Na_2SiO_3 emulsion, but the dominant factor for that in the latter two caustics was caustic concentration. Table 5 shows concentration affecting phase conversion in three different caustic solutions. Obviously, the influence by formation water in the said systems decreased as the caustic strength increased. In other words, the main factor

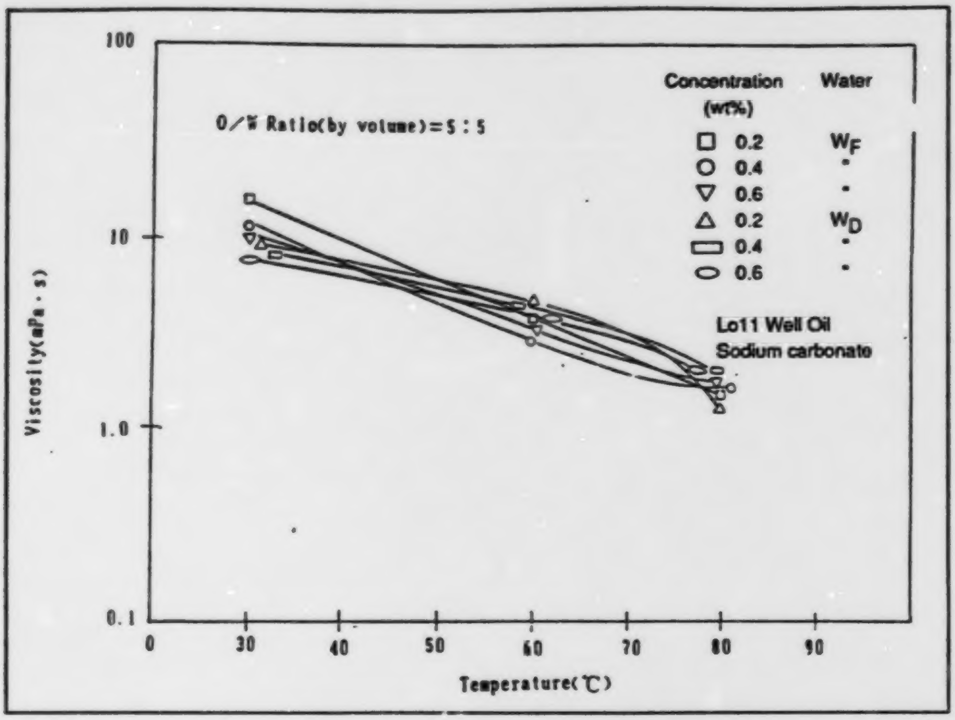


Figure 12. *Viscosity versus temperature with comparison between formation and distilled water under a low O/W ratio.*

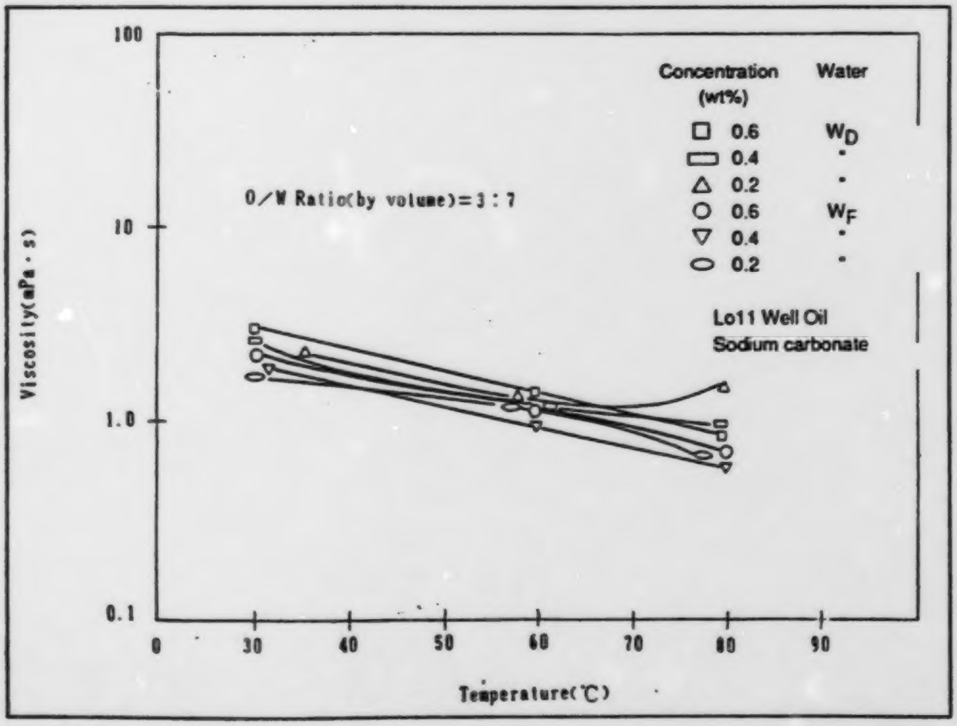


Figure 13. *Viscosity versus temperature with comparison between formation and distilled water under a low O/W ratio.*

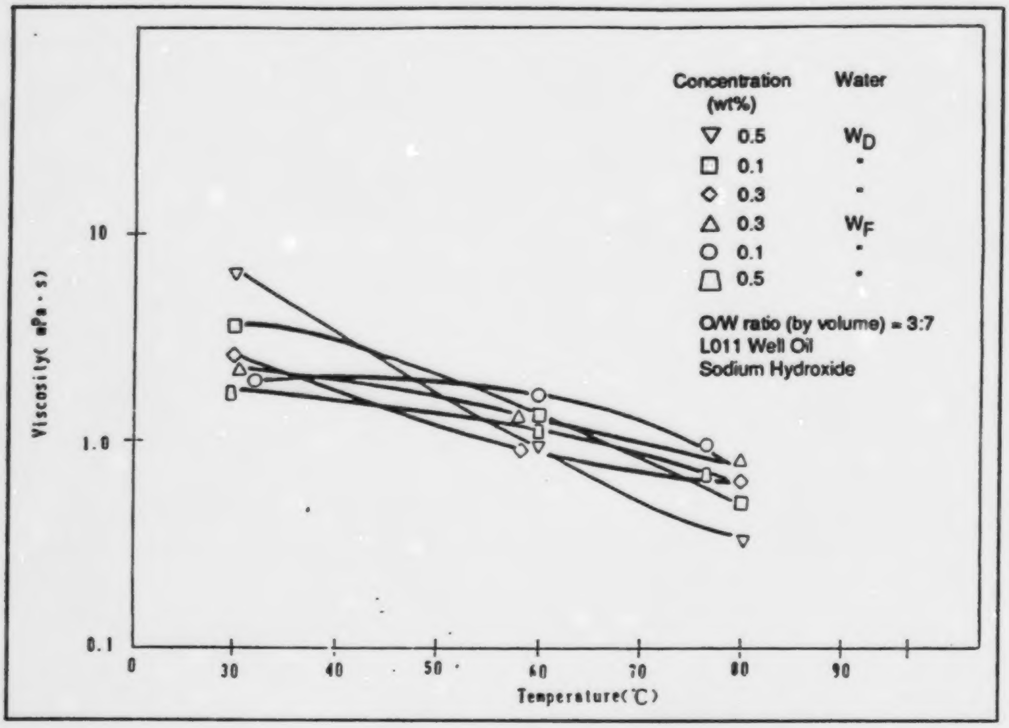


Figure 14. *Viscosity versus temperature with comparison between formation and distilled water under a low O/W ratio.*

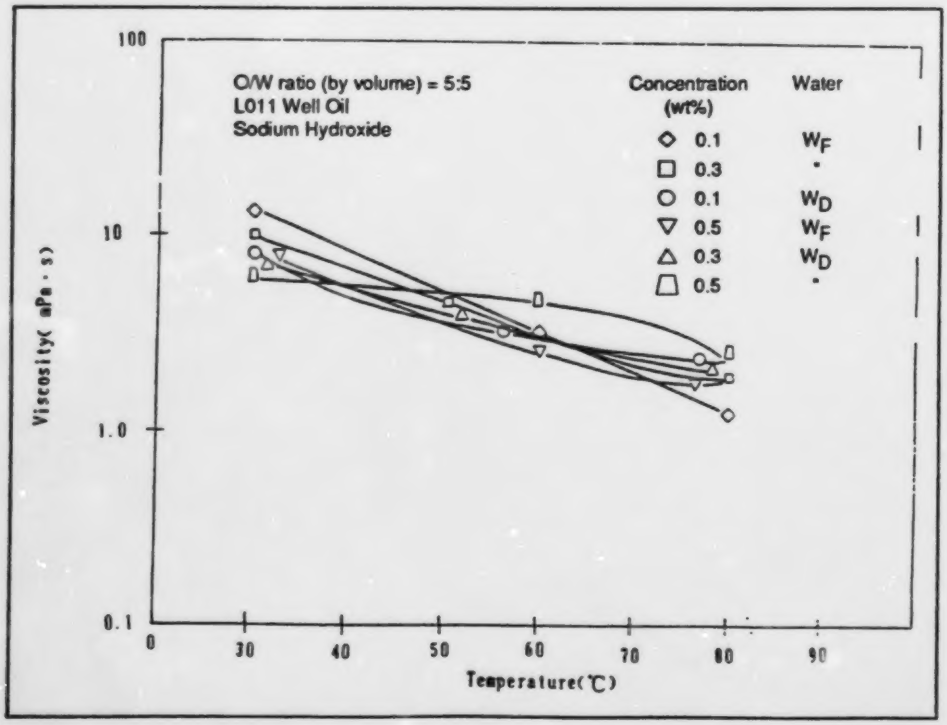


Figure 15. *Viscosity versus temperature with comparison between formation and distilled water under a low O/W ratio.*

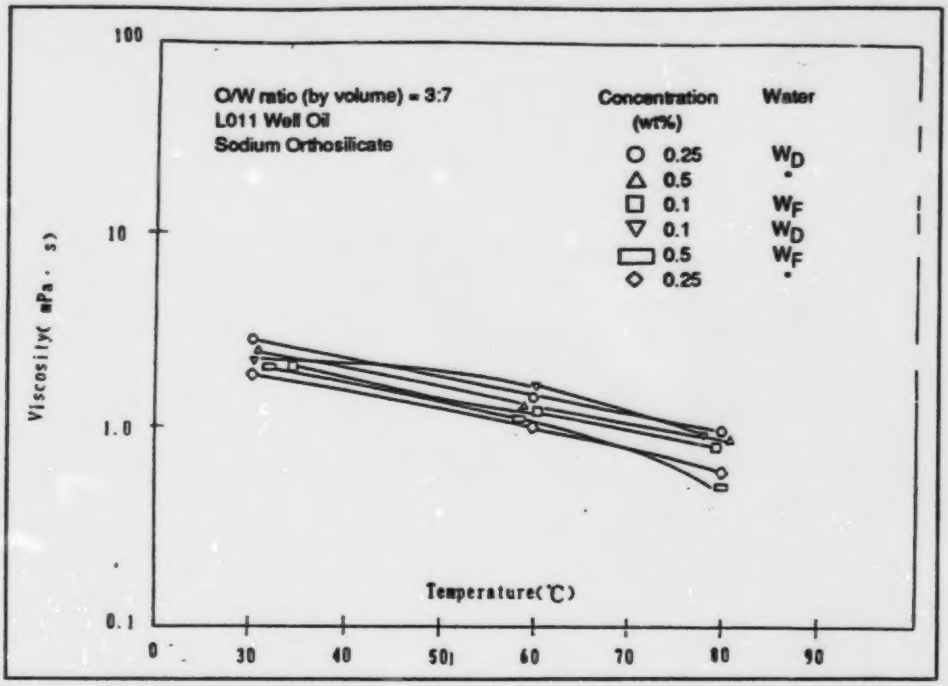


Figure 16. Viscosity versus temperature with comparison between formation and distilled water under a low O/W ratio.

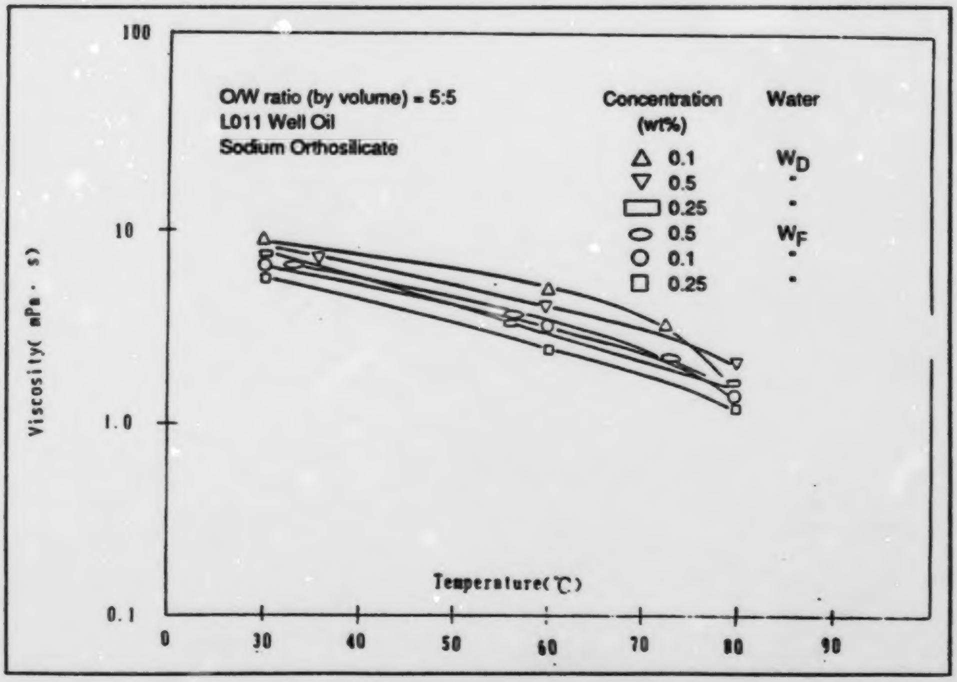


Figure 17. Viscosity versus temperature with comparison between formation and distilled water under a low O/W ratio.

Table 3. The effect of formation brine on viscosity at low O/W ratio (mPa·s)

		O/W ratio	O/W ratio
Disperse phase	Caustic	5:5	3:7
	Na_2CO_3 (0.2 to 0.6 wt%)	1.3 to 9.0	1.0 to 3.0
Distilled water	NaOH (0.1 to 0.5 wt%)	2.1 to 8.0	0.6 to 6.5
	Na_4SIO_4 (0.1 to 0.5 wt%)	1.5 to 8.5	0.85 to 2.8
	Na_2CO_3 (0.2 to 0.6 wt%)	1.4 to 15	0.65 to 2.5
Formation water	NaOH (0.1 to 0.5 wt%)	1.2 to 13	0.6 to 3.0
	Na_4SIO_4 (0.1 to 0.5 wt%)	1.2 to 7.5	0.5 to 2.5

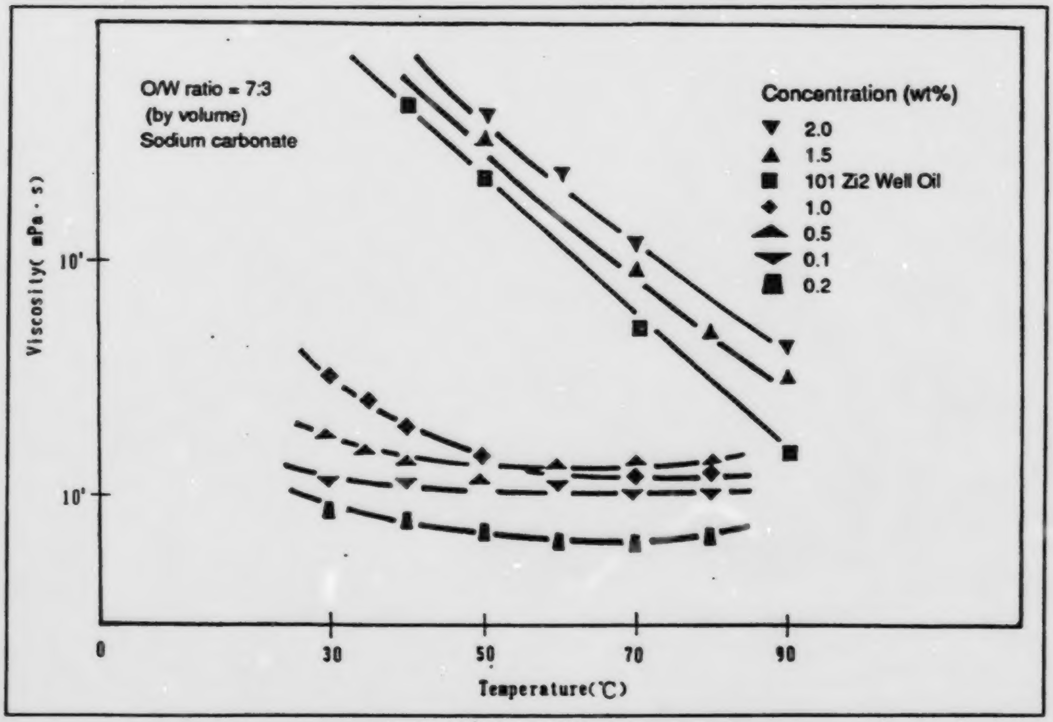


Figure 18. Viscosity versus temperature at a higher O/W ratio and distilled water.

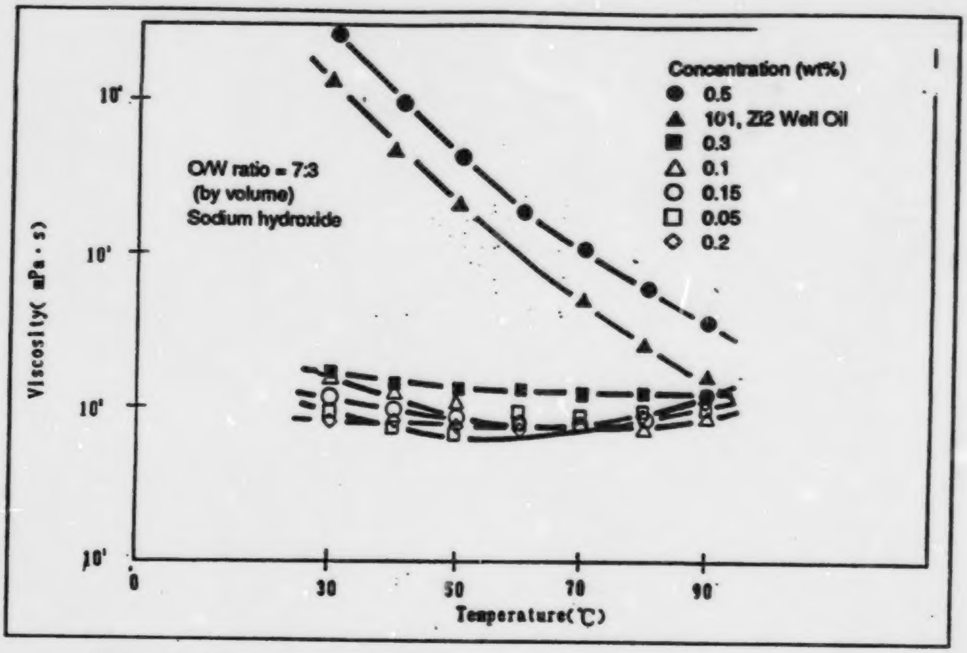


Figure 19. Viscosity versus temperature at a higher O/W ratio and distilled water.

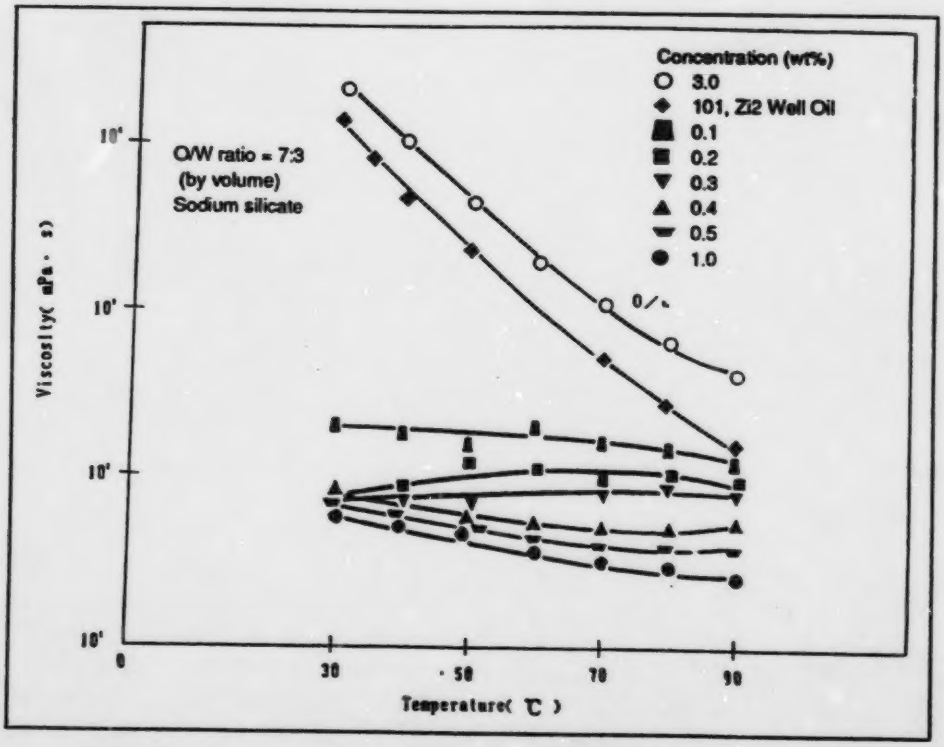
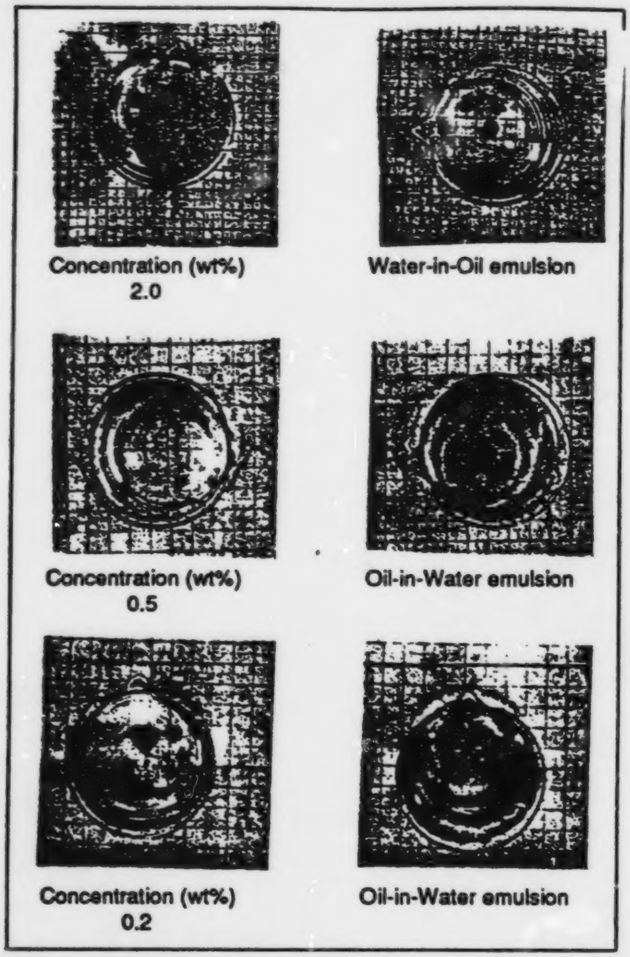
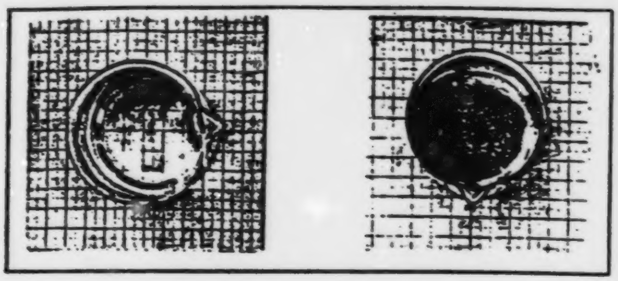


Figure 20. Viscosity versus temperature at a higher O/W ratio and distilled water.

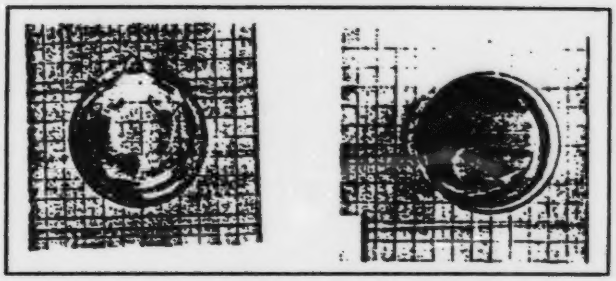


O/W ratio (by volume)	Left liquid	Right liquid	Temperature (°C)
7:3	Kerosene	water	30

Figure 21. Compatibility of emulsions – sodium carbonate.



Temperature (°C) = 70
O/W ratio (by volume) = 7:3
Oil-in-water emulsion



Temperature (°C) = 30
O/W ratio (by volume) = 6:4
Oil-in-water emulsion

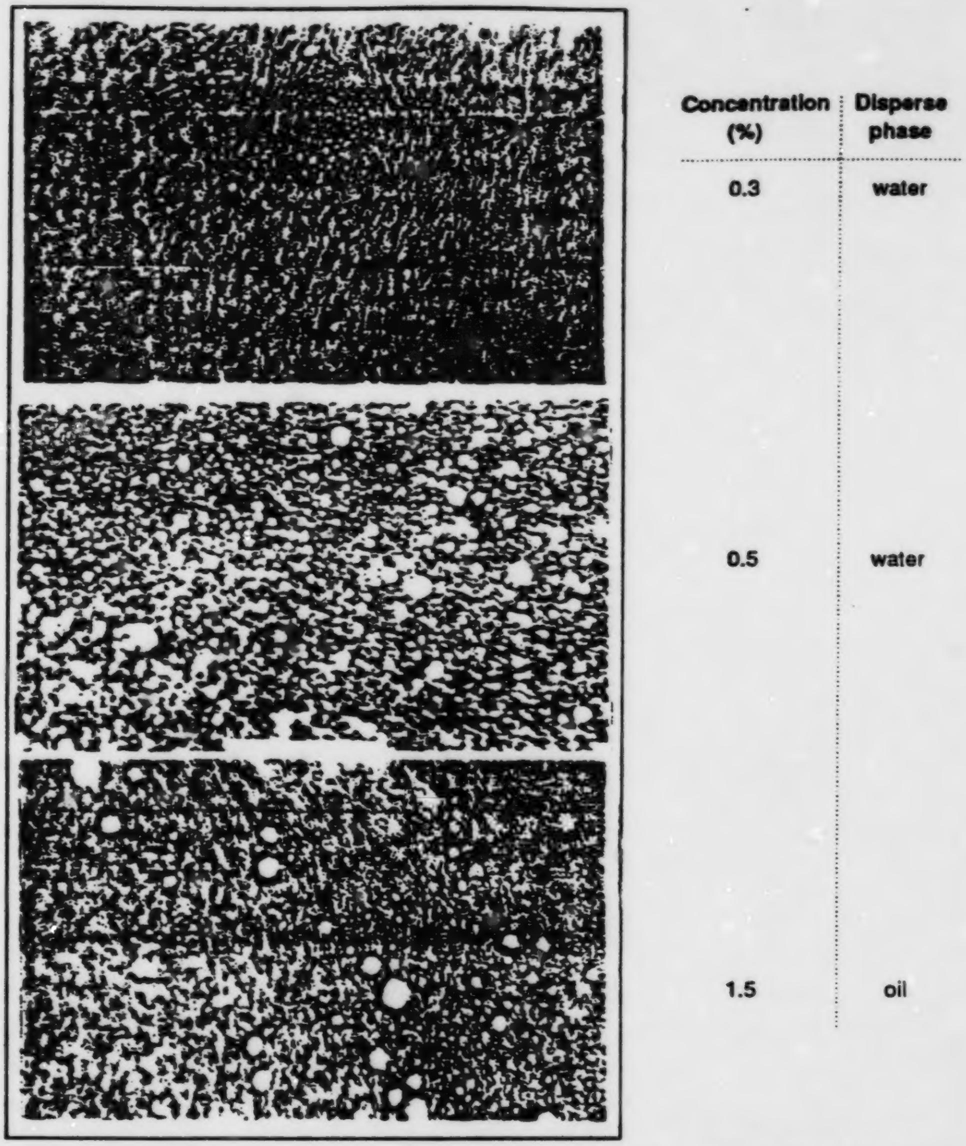
Concentration (wt%)	Left liquid	Right liquid	Caustic
0.2	Kerosene	Water	Sodium carbonate

Figure 22. Compatibility of emulsions at different temperature and oil-water ratio.

controlling phase conversion in these solutions at a higher oil-water ratio was alkalinity, not temperature.

Driving mechanisms for oil displacement.

(a) Size of droplets and its distribution in emulsions. The emulsions were prepared by using three caustic solutions at different concentrations with the Jinglou crude at oil-water ratio of 3:7. Figure 27 displays photomicrographs and Table 6 shows the droplet size and its distribution in these emulsions. The results indicate that 99% of the total droplets in emulsions exhibited a radius of less than 2.5 μm, and its size distributions were uniform. However, the estimated average radius of the pore throat in the Jinglou reservoir rock is 23.5 μm, which is about 10 times that of the droplets size in emulsions. According to Barkman, Banidon[15], this pore throat to droplet ratio is favorable for oil displacement at certain low oil-water ratio (higher water cut) in the Jinglou reservoir. Emulsification and entrainment will play major roles in this case.



Magnification = 74 O/W ratio (by volume) = 1:1 Temperature (°C) = 20

Figure 23. Microphotographs of sodium carbonate emulsion.

(b) Flexible characteristics of Na_2CO_3 solutions. From our observation, Na_2CO_3 solutions exhibited such flexible quality in the laboratory tests. For example, it created high viscosity in emulsions in the tests at high oil-water ratio and high concentration in the distilled water (Figure 18); or in the test at low concentration with formation water involved (Figure 24). In the latter, the measured emulsion's viscosity was 300 mPa·s to 350 mPa·s higher than the oil's viscosity at the temperature between 30°C to 90°C. On the contrary, it caused a rising viscosity with the increasing temperature in the fresh water with high oil-water ratio (Figure 9). These flexible

Table 4. Concentration boundary of phase conversion of three caustics in distilled water

Caustic	NaOH	Na_2CO_3	Na_2SiO_3
O/W ratio (W_D)	7:3	7:3	7:3
Temperature (°C)	30 to 90	30 to 90	30 to 90
Concentration of phase conversion (wt%)	0.3 to 0.5	1.0 to 1.5	2.0 to 3.0

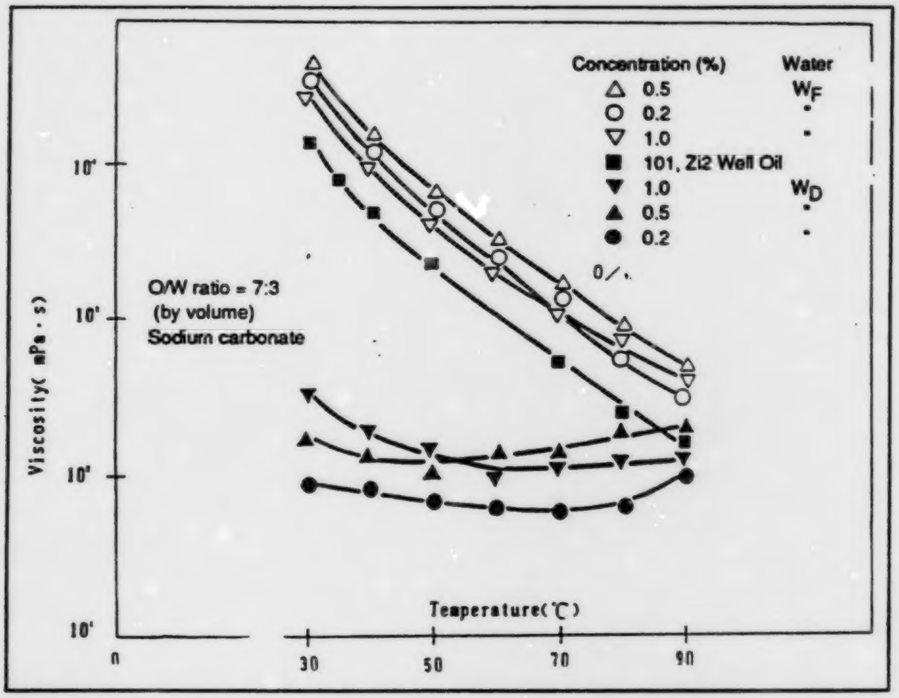


Figure 24. Viscosity versus temperature with comparison between formation and distilled water at a higher O/W ratio.

characteristics of Na_2CO_3 solutions could be utilized for enhanced oil recovery in certain heavy oil reservoirs.

DISCUSSIONS

1. The formation water with a low salinity (600–8027 mg/L) in the Jinglou reservoir contained calcium of 10 to 44 mg/L and magnesium of 0 to 26 mg/L. The high acid number averaged 3.63 mg/g on 13 wells (2.9 to 4.36 mg KOH/g) was observed in the Jinglou crude. These factors will benefit caustic waterflooding the Jinglou heavy-oil reservoir.
2. The high content of organic acid (1.0 wt%) in the Jinglou crude is the basis of creating low IFT and emulsification when the oil is mixed with caustic solutions. Our tests based on three different caustics indicated that we could prepare good quality emulsions and achieve low IFTs (10 E-2 mN/m).
3. In studying oil-in-water emulsions, the decreasing emulsion's viscosity occurred with the increasing temperature when the oil-water ratio was less than 5:5. Contrary to this, the rising emulsion's viscosity was observed at the escalating temperature (oil-water ratio greater than 5:5). To the latter, the authors believe that higher oil content at the rising temperature created dispersion in emulsions. The particles movement caused friction due to thinner water film among them. This results in higher viscosity at higher temperature.
4. At the optimum temperature and caustic concentration in the tests, the lowest IFT can be obtained. This indicates that the maximum amount of surfactants could be generated in these conditions when the caustics acted with the organic acids in the Jinglou crude. Moreover, the effect of formation water on IFT might have been

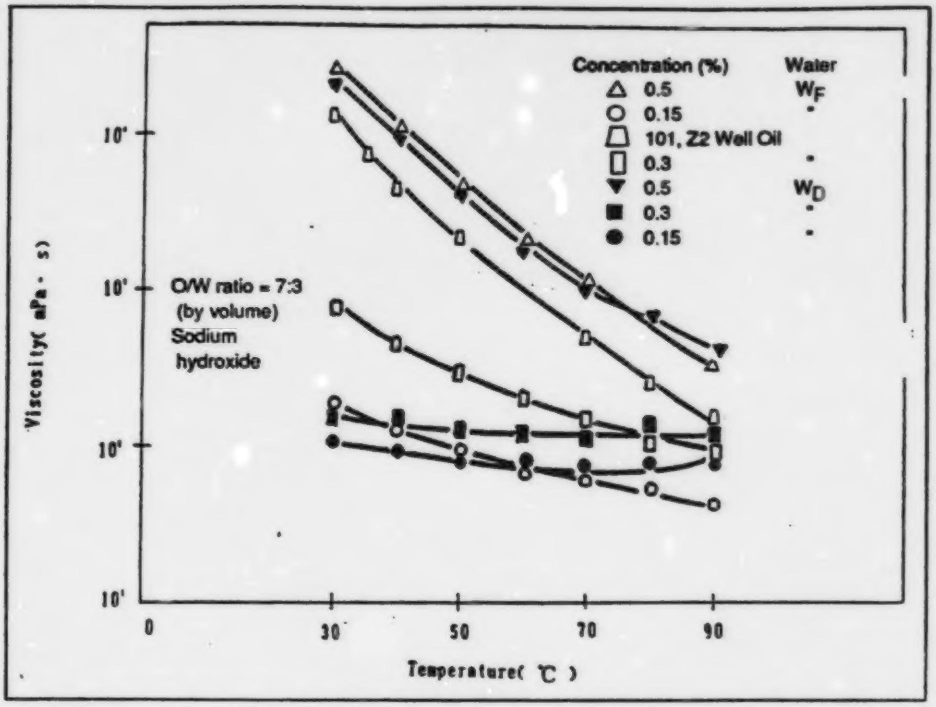


Figure 25. Viscosity versus temperature with comparison between formation and distilled water at a higher O/W ratio.

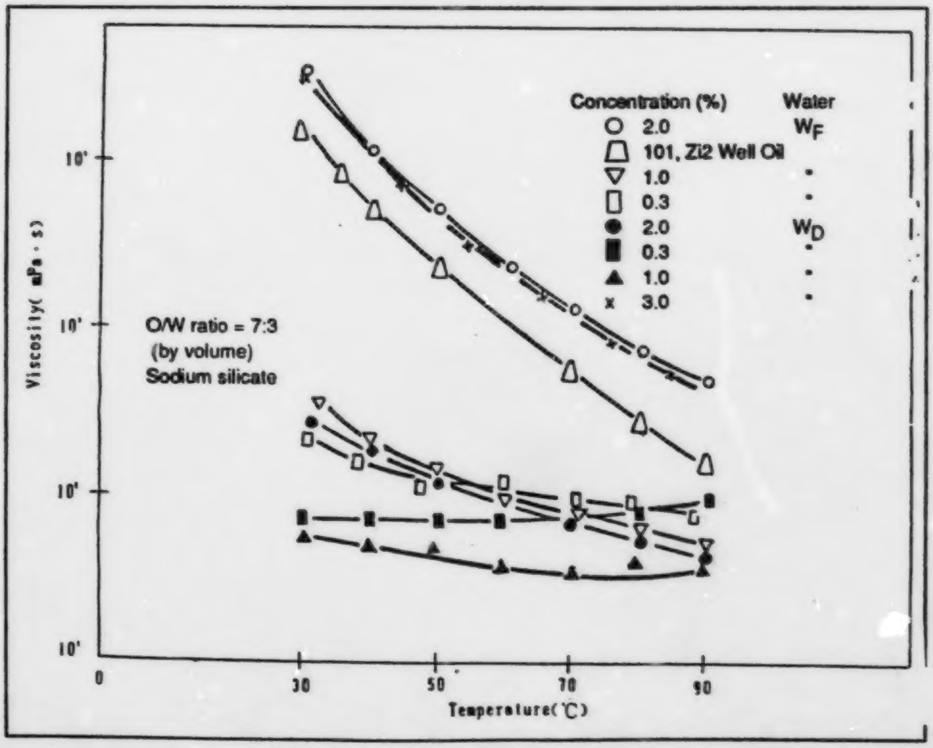
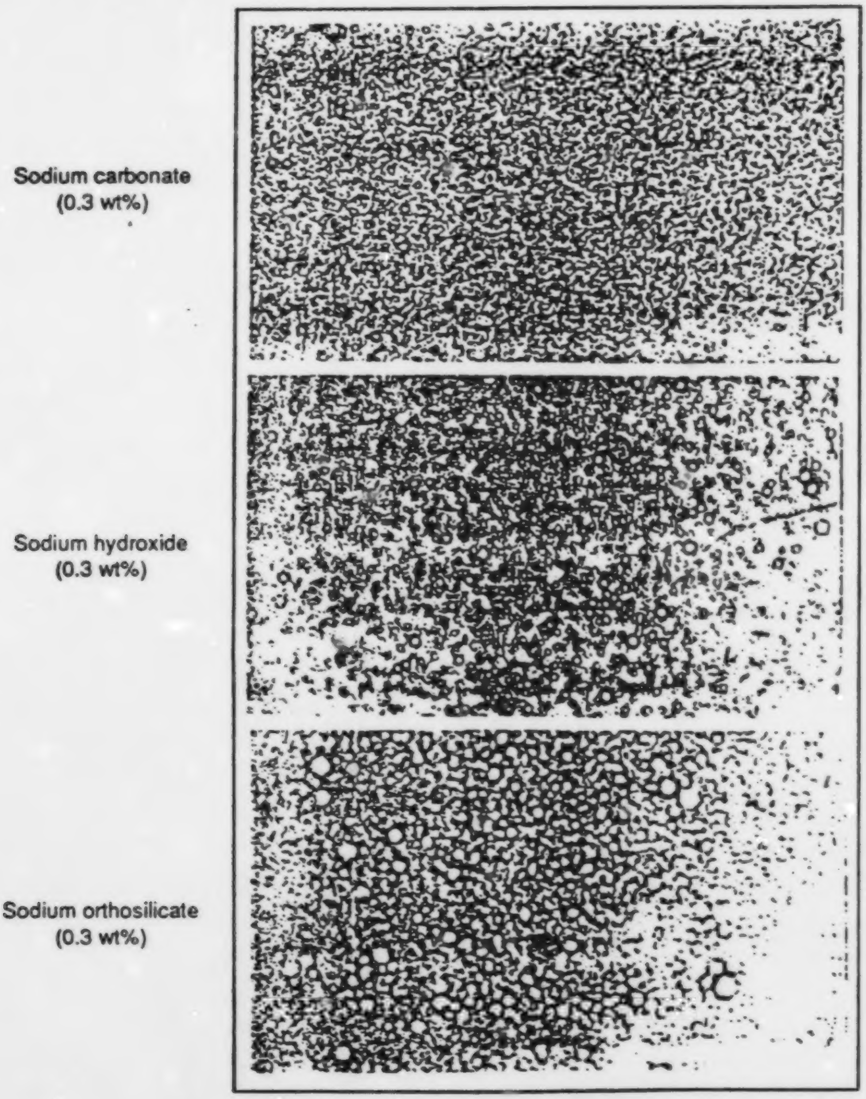


Figure 26. Viscosity versus temperature with comparison between formation and distilled water at a higher O/W ratio.

Table 5. Concentration boundary of phase conversion of three caustics in formation brine

Caustic	NaOH	Na_2CO_3	Na_2SiO_3
O/W ratio (W_f)	7:3	7:3	7:3
Temperature (°C)	30 to 90	30 to 90	30 to 90
Concentration of phase conversion (wt%)	0.3 to 0.5	all occurrence	1.0 to 2.0
Concentration change of phase conversion	not	all change	fall
Alkalinity	most strong	weak	strong


Sodium carbonate (0.3 wt%)
Sodium hydroxide (0.3 wt%)
Sodium orthosilicate (0.3 wt%)

O/W ratio (by volume) = 3:7 Oil-in-water emulsions

Figure 27. Microphotographs of three caustic emulsions.

Table 6. The droplet distribution of three caustic emulsions at an O/W ratio of 3:7

	Droplet distribution (quantity ratio)	
Caustic	g > 2.5 mm (%)	g > 2.5 mm (%)
NaOH (0.1 wt%)	0.2	99.8
NaOH (0.3 wt%)	0.2	99.8
$NaSiO_4$ (0.05 wt%)	1.5	98.5
$NaCO_3$ (0.3 wt%)	0.9	99.1
$NaCO_3$ (1.0 wt%)	0.3	99.7

caused by high solubility of calcium soap in the said oil.

CONCLUSIONS

1. The properties of crude oil and formation water in the Jinglou reservoir provide a suitable basis for enhanced oil recovery by hot caustic waterflooding.
2. At the temperature of about 60°C, the achieved lowest IFT of three caustics with the Jinglou crude was less than 10 E-2 mN/m at the concentration of 0.5 to 1.0% by weight.
3. The emulsion's viscosity was significantly affected by oil-water ratio. For instance, at the same temperature with increasing oil-water ratio, the said viscosity rose from several to several hundreds mPa·s. When oil-water ratio was less than 5:5 by volume, the emulsions behaved like ordinary fluids. When it was greater than 6.4, the changing emulsion's viscosity with the increasing temperature decreased at the beginning and built up later.
4. The phase conversion was dominated by caustic concentration at higher oil-water ratio of 7:3 for Na_2CO_3, NaOH, and Na_2SiO_3 in the fresh water. The critical concentrations in this case were 0.3 to 0.5, 1.0 to 1.5, and 2.0 to 3.0, respectively for the mentioned caustics.
5. For the solutions prepared by using formation brine at the oil-water ratio of 7:3, emulsions of Na_2CO_3 changed from oil-in-water to water-in-oil type in all tested concentrations. The emulsion's viscosity of the latter was greater than the oil viscosity. The critical concentration of phase conversion reduced from 2.0–3.0 wt% to 1.0–2.0 wt% for Na_2SiO_3 solutions. It was not, however, influenced by formation brine in the NaOH solutions.
6. The results of this investigation have provided the basis for feasibility study for hot caustic waterflooding this reservoir.

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IN SITU COMBUSTION IN CANADA

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ABSTRACT

In situ combustion pilot projects have been conducted in Canada since the 1950's. Commercial projects commenced in the 1960's, and research commenced at the University of Calgary in the 1970's.

Several Canadian projects will be reviewed and the problems associated with these projects discussed. In Canada both oxygen enriched air and normal air have been employed in combustion. The advantages and disadvantages of oxygen enriched air will be presented.

At the University of Calgary the mechanism of combustion has been studied in combustion tubes, thermal cracking experiments and in low temperature oxidation reactors. Some of the factors which affect ignition, vigor of the burn, and fuel consumption will be discussed. Parameters which should be consistent in the design and operation of an in situ combustion project will also be presented.

INTRODUCTION

In situ combustion pilot studies began in Canada in the early 1950's with reverse combustion pilots in the Athabasca oil sands deposits. These studies were followed by forward combustion studies (Jenkins et al., 1979). Commercial projects were started by Mobil in the Battrum reservoir in Saskatchewan in the 1960's. Husky also started pilots in Saskatchewan in the 1960's. Since that time pilots have been run by a number of companies: Dome (Lindberg–Morgan), Norcen (Bodo), PanCanadian (Countess), Alberta Energy Company (Suffield), Gulf (Pelican Lake), Unocal (Buffalo Lake), General American (Pelican Lake), Petro Canada (Kinsella), Esso (Joracam), Murphy (Eyehill–Silverdale), and BP (Cold Lake).

An in situ combustion group (ICG) was formed at the University of Calgary in 1973. The main objective of the group was to study the mechanism of combustion. This group has studied the kinetics of the combustion process, ignition mechanisms, mathematical modeling of combustion and, dry, wet and enriched air combustion techniques. The ICG have worked closely with industry in the design and monitoring of their pilots.

With the decline of oil prices in 1986 it became uneconomical to operate the Canadian pilots so most of these have been shut in. With increases in oil prices there will probably be renewed interest in this process.

Since Canada started using the combustion process many advancements have been made to solve some of the problems associated with the in situ combustion process. In situ combustion is probably the most complicated and difficult process of all EOR methods. In situ combustion does not behave like any other EOR process, and many of its failures result from operators not understanding the process, and not putting knowledgeable individuals in place to supervise the project. It requires many man hours of careful engineering, operations supervision, and research to operate a successful project. It also requires special monitoring and production equipment and requires an operator to be flexible and ready to change operating procedures.

This paper will discuss the following:

1. Combustion processes
2. Canadian operation problems and solutions
3. In situ combustion group research

COMBUSTION PROCESS

In situ combustion can be operated in the reverse or forward mode. In the reverse mode the producing well is ignited and the fire moves from the producer to the injector. The fuel is the reservoir crude oil. This process has been tried in the field but has not been very successful. In forward combustion the injection well is ignited and the fire front moves from the injection well to the producing well, the fuel is the heavy residual coke left on the rock matrix. This type of combustion is commonly used in most in situ combustion projects today.

Combustion temperatures reach 400–800°C in the reservoir. In order to recover heat left behind by the fire front, water is often injected. The ratio of the air to water determines the mode of burning that will occur in the reservoir. Small amounts of water do not affect the peak temperature where high rates of water injection give long steam banks and may reduce the peak temperature to the steam bank temperature. This latter type of combustion is referred to as quenched, or superwet combustion (Dietz et al., 1968, Parrish et al., 1969, Bennion et al., 1977).

It has been recognized for some time that oxygen has certain advantages over air for in situ combustion in some reservoirs. Less volumes of gas need to be injected and produced. The combustion gases are primarily CO_2 which can reduce the oil viscosity and increase sweep efficiency. Oxygen was first injected by Greenwich Oil Company in East Texas into a heavy oil reservoir. They were also the first company to go commercial with an oxygen injection project. Oxygen has also been injected into several Canadian reservoirs by Husky, Petro Canada, Gulf, BP, and Dome. Oxygen injection can be conducted in either a dry or wet mode.

CANADIAN OPERATIONAL PROBLEMS AND SOLUTIONS

In situ combustion projects have usually had a number of operational problems; the Canadian pilots have been no exception. Tabulated below are a number of problems which have been encountered:

1. Channeling of air or oxygen
2. Uneven advance of the combustion and gas fronts
3. Ignition
4. Monitoring
5. Water influx
6. Pumping problems Hycal
7. Sand production
8. Formation of stable emulsions
9. H_2S production
10. Explosions
11. High temperatures

Each of these problems will be discussed:

1. **Channeling of air.** On several projects air has channeled from the injection to the producers very quickly and large amounts of unreacted oxygen have been produced. Special processes have been developed and patented to overcome this problem. These processes make use of the fractures and high permeability streaks to enhance the recovery of oil. BP has patented a process to use combustion in a fractured reservoir (either naturally or man made fractures) (Hallam et al., 1988a). The process was developed for the Cold Lake oil sands reservoir, and was to follow the completion of cyclic steam stimulation conducted above fracturing pressure. The process consists of the following:

   a. A combustion front is initiated from the injection well.

   b. Oxygen and water are injected to propagate the front through the channels towards the production wells. During this phase the production wells are operated without restriction.

   c. After heat breakthrough but before the burning front reaches the production well the production rate is restricted.

   d. Continue to inject and build the reservoir pressure. This forces the burning front into other channels.

   e. As heat breaks through into other wells, these rates are restricted until all wells are in communication with the injectors.

   f. Continue to inject until a significant increase in reservoir pressure occurs.

   g. Terminate oxygen injection and inject sufficient water into the channel system to cool it to a temperature below which coking of the oil will occur.

h. Open all producers and blow the reservoir down. Repeat steps a through h.

This process has been very successful in the pilot stage and plans have been made to put it into a commercial operation (Hallam et al., 1988b).

Husky experienced channeling in their Tangle Flags pilot and found that by reducing injection rates and pressure cycling that they reduced oxygen breakthrough and experienced increased production of oil (Tsang, 1989).

2. **Uneven advance of combustion fronts.** Most Canadian combustion pilots have been pattern type floods. Fireflooding is different than most types of floods. For a five-spot pattern the fronts approach a well from four directions simultaneously. With waterflooding premature breakthrough from one direction causes little problem. In fireflooding it may mean shutting in the well or losing a well from high temperatures. The operator has little control of the advance of the firefront. Therefore, patterns should not be used. Air or oxygen should be injected structurally high in the reservoir and the down-dip wells produced and new wells drilled to capture the maximum amount of oil. For large reservoirs the line-drive approach can be used.

   Several combustion projects have been unsuccessful in getting good sweep because they went to a pattern type flood (Miller et al., 1988). In the reservoir described in this paper they tried steam, CO_2 and air stimulation on some producing wells to get the firefront to move toward them, but had no success in moving the firefront towards those wells.

3. **Ignition.** For a fireflood to be successful the burn should be vigorous, yielding good H/C ratios and have good high temperature oxygen utilization. We have had problems getting good ignition in some wells and in maintaining combustion. Miller et al., 1988 described the problem encountered in Golden Lake. D'Souza et al. (1988) described a down hole brine which they developed to get good ignition in low pressure reservoirs. Farquharson et al. (1986) described modifications to the ignition process which were made to get good ignitions and to prevent down hole explosions.

4. **Monitoring.** Monitoring techniques and corrective procedures have been developed by the In Situ Combustion Group at the University of Calgary. These will be discussed later in the research section of the paper. The application of these procedures in the field are discussed in three papers (Bojes et al., 1989), (Moore et al., 1984), (Hallan et al, 1990).

5. **Water influx.** In situ combustion does not behave like other injection processes and it is very difficult to maintain or increase reservoir pressure. The injected gas is very mobile and most of it is produced along with other reservoir fluids. Therefore reservoirs with active aquifers may encroach and adversely affect the combustion front performance. Golden Lake and Eyehill are reservoirs which exhibit this type of behavior. Combustion, however, also sometimes inhibits water coning in reservoirs (Farquharson et al., 1986).

6. **Pumping problems.** Because of viscous emulsions, sand production and high gas-oil ratios many reservoirs have experienced pumping problems. In fireflooding processes it is imperative that oil displaced to a well be captured and produced.. Well workovers and well down time affects the economics of many firefloods. Petro Canada and Murphy have presented some of the information which they discovered helped to increase pumping efficiency.

   Wells are completed with 73 or 89 mm EUE tubing, to help prevent rod fall problems. Tubing tails are located below the bottom perforations to allow gas breakout in the annulus. Hollow

Sucker rods (27 mm) are used to inject diluent on some wells. Moyno pumps are used on wells with rod fall problems.

Insert pumps are used with 0.076 mm clearance. Unless sand is being produced then 0.15 mm clearance is used. High fluid volumes, long strokes, and fast pumping speeds have proven effective in producing solid laden fluids. Pumps are spaced out with the plunger running as close as possible to the bottom of the stroke so as to maximize compression ratio.

> "Diluent injection pumps have been used successfully on EOR fireflood wells which produce viscous emulsions. The design used by Petro-Canada allows the diluent to be injected at a port on the plunger immediately above the travelling valve. The plunger has increased clearance below the injection port so that diluent can flow down into the chamber between the standing valve and travelling valve, mix with the produced fluids, and pass through the travelling valve and plunger. Stuck standing valves can be cleaned by stopping the pump, shutting in the tubing and injecting diluent until the tubing pressures up, indicating that the standing valve has again seated." (Duncan, 1984).

Murphy (Farquharson et al., 1986) also designed and patented a down hole pump containing a specially designed fluid injection valve. This valve introduces fluid from a surface source via hollow sucker rods into the pump chamber at the end of the intake cycle (downstroke) to completely fill the pump barrel and eliminate pump inefficiencies caused by gas locking.

Sand production is handled by using a combination of polymer rings and seats and hardened surfaces give the pump good wear characteristics.

Manufacturers in Canada have spent some effort in developing pumps to handle sand laden fluids. Moyno or screw type pumps have been successful in some fields in producing these types of fluids as long as the wells are not operating at elevated temperatures.

7. **Sand production.** In most combustion projects large volumes of gas are usually produced. These, along with emulsified oil, tend to increase sand production. This results in frequent well servicing and sand handling equipment on the surface. Well servicing constitutes one of the major lifting costs in some projects. These costs consist of service rig time to repair sanded in wells, down hole pump repairs and replacement of sand eroded equipment (liners, chokes, elbows, etc.).

In Canada two approaches to sand control have been used. The first and most successful in many fields is to produce the oil and entrained sand, and tolerate the increased servicing costs. The second is to use sand retaining devices. These devices consist of:

1. consolidating the sand in the wellbore vicinity
2. gravel packs
3. slotted liners
4. screens
5. specially designed filters

In many reservoirs these devices are eroded out by the abrasive sand, or they impede production. However, in some reservoirs they have been very successful (Marjerrison et al., 1988), (Duncan, 1984).

8. **Emulsions.** In situ combustion results in chemical reactions occurring between the injected oxygen and the reservoir crude oil which produce emulsifying surfactants. High velocities are also often experienced in the vicinity of the wellbore causing turbulent flow in the rock matrix which tends to emulsify the crude oil. In Canada we have very low BS and W pipeline specifications so the production has to be treated to less than 1/2 of a percent of water. This treatment consists of specially designed de-emulsifiers, and in some reservoirs specially designed dehydrators. Farquharson et al. (1986), describes an evaporation dehydrator. Evaporation dehydrators are in place in several thermal projects in Canada. In some projects all that is required are

free water knockouts, chemicals, and a treater equipped with electrostatic grids.

9. **H_2S production.** All of Canada's heavy crudes and oil sands contain sulphur. One of the products of combustion is H_2S. Much of this reacts with the reservoir rock and water but at times some is produced. Most projects contain a gas gathering system to collect vented annulus gas. This gas is usually incinerated and vented through a stack. With the concern to the environment of acid rain and the greenhouse, effect venting of these types of gas may not be possible in the future. If pure oxygen is injected, the majority of the gas will be CO_2. This can be collected, dehydrated, compressed and used in other enhanced oil recovery projects.

10. **Explosions.** In Canada explosions have occurred in wells, compressors, and injection lines. Precautions should be taken to use proper compressors, oils, and scrubbers. Injection wells should never be allowed to back flow during the ignition stage and early stages of a fireflood. Production wells should be kept cool and shut in before explosive mixtures are produced.

11. **High temperatures.** As the fire front approaches a well, provisions should be made to cool the well. It is important that cooling water be circulated past the perforations of the well being produced. If the well is to be shut in, the water should be injected into the formation until the well cools. Several companies have used high temperature metals over the producing interval (Duncan 1984). Jenkins et al., 1979 gives the following specifications for an optimum producing well:
    a. sand free production
    b. able to withstand cyclic-temperature changes
    c. able to withstand high bottom hole temperatures
    d. can be cooled
    e. able to monitor downhole temperatures.

IN SITU COMBUSTION GROUP RESEARCH

This group consisting of D.W. Bennion, R.G. Moore and J.K Donnelly along with a group of research assistants and graduate students was founded in 1973 in the Department of Chemical and Petroleum Engineering at the University of Calgary. The group has been funded by NSERC, AOSTRA, CANMET, and Alberta Environment and Industry and has developed equipment and techniques to study the mechanism of combustion. Tabulated below are some of the areas research has been conducted in:

1. thermal cracking
2. low temperature oxidation
3. wet combustion
4. monitoring tools
5. effect of various parameters on combustion
6. oxygen fireflooding
7. mathematical modeling
8. ignition
9. modes of combustion

The group's first effort was to construct an adiabatic combustion tube. After running several tests on this apparatus it was found that different equipment would be needed to study individual mechanisms. The following apparatus have been assembled:

1. Batch thermal cracking reactor
2. Low temperature oxidation stirred reactor
3. Low temperature oxidation plug flow reactor
4. Low temperature temperature ramped reactors
5. Thermal conductivity apparatus
6. Radial burning apparatus
7. A combustion tube to burn consolidated cores

1. **Thermal cracking.** The main thrust of this work was to develop thermal cracking kinetics data which could be used in a compositional thermal simulator. Previous researchers believed that these reactions controlled the fuel lay down. ICG was the first to develop compositional kinetic data. When this was placed in a numerical

simulation, it was found that thermal cracking could not account for all the fuel which was deposited. (Hayashitani et al, 1977, 1978), (Bennion et al., 1977), (Millour et al, 1985)

2. **Low temperature oxidation.** During the process of studying wet combustion it became apparent that low temperature oxidation plays an important role in the process. When the kinetics were included in the numerical simulation, it was possible to match fuel laydown. The experiments have also allowed us to better understand the ignition process and the stability of the combustion front. Recent work has shown that many reservoirs try to revert from a high temperature mode of burning to a low temperature oxidation mode. Work is being done to use additives to convert back to the high temperature mode. The following papers have been published in this area: (Adegbesan et al., 1983,1986, 1987), (Millour et al., 1986), (Moore et al, 1986).

3. **Wet combustion.** ICG has done a large amount of research to optimize water/air ratio for improving the process. We have found that the process is very dependent upon the pressure being used and that using too much water can be detrimental (Bennion et al, 1977, 1978), (Ejiogu et al, 1979), (Moore et al., 1979,1984,1987)

4. **Monitoring.** To better understand what is happening in the reservoir the ICG has performed detailed analysis on all the produced fluids. They have also run stable isotope analyses. The ICG have found these to be very beneficial in interpreting what is happening in the laboratory and the field. Many of our laboratory procedures have been employed in the field (Bennion et al., 1977,1978), (Moore et al., 1984).

5. **Effect of various parameters.** ICG has investigated the following parameters:

   a) flux rate

   b) pressure

   c) water/air ratio

   d) wettability

   e) oxygen concentration

   f) steam-air-oxygen

   We have found that with some reservoirs a low flux rate is required; with others a high flux rate is beneficial. The higher the pressure the greater the tendency for the reservoir to burn in the low temperature oxidation mode. Each reservoir has an optimum air/water ratio which must be determined experimentally. Low oxygen concentration will sometimes help to switch burning modes. Oil wet reservoirs lay down more fuel than water wet reservoirs. (Vondeau et al., 1980), (Moore et al., 1988).

6. **Oxygen fireflooding.** ICG with the help of industry and a matching grant from the Province of Alberta modified the combustion tube to operate on pure oxygen at pressures to 3000 psi. Numerous runs have been made to study the mechanism of oxygen fireflooding. Our main findings are that if air will not work, oxygen will not. Oxygen has the advantage of producing C02 and less gas has to be handled. We have safely used °2 in the laboratory and in the field. A large number of research and engineering studies should be performed before using oxygen in a reservoir. ICG believes it has potential provided it is used properly. (Moore et al., 1987)

7. **Mathematical models.** ICG mathematical model efforts have been in the use of compositional thermal numerical simulators. We have found that present models are useful for studying mechanisms. Many of the kinetic parameters are grid block size sensitive so it makes it very difficult to perform field scale simulations unless a constant size grid block is used throughout the reservoir. ICG has used commercial models, as well as written their own (Sibbald et al., 1988), (Belgrave et al., 1990).

8. **Ignition.** Experimental studies were conducted using additives to enhance ignition. Several liquid phase additives were used. No papers have been published on this work yet.

9. **Mode of combustion.** Many Canadian projects have not performed as expected; therefore ICG has spent a lot of time studying why some fields do not burn vigorously. We have also made recommendations on how to improve the burning process. A lot of experimental work has been performed to determine why the process remains in the LTO mode or switches from the higher temperature mode to LTO. Work is progressing in the area of gas-phase burning and flame front stabilization. (Sibbald et al., 1988), (Moore et al, 1988).

SUMMARY

Over the last 40 years Canada has made a significant contribution to the science of in situ combustion. ICG has helped design firefloods in Canada, USA, Turkey and Peru. In situ combustion is a very complicated process and requires patience, manpower, and a low rate of return on investment, but it may be the only process that can be applied to thin or very deep reservoirs.

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CHEMICAL SIMULATION OF IN-SITU COMBUSTION PROCESS AND THE ASSOCIATED THERMOKINETIC OF OXIDATION OF HEAVY OIL*

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ABSTRACT

This paper presents the results of thermokinetics in chemical simulation of in-situ combustion process. The goals of this study are:

1. *To investigate the oxidation mechanism of heavy oil with a compound, n-Dotriacontane.*
2. *To obtain the key parameters, which affect not only the energy balance in numerical simulation of in-situ combustion processes, but also the performance of field tests.*

An improved microcalorimetric technique and a thermokinetic model developed by the Institute of Chemistry, Academia Sinica were used for this study. The results of this model, which presents the thermal power of reaction (such as oxidation of heavy oil in porous medium) as a function of time, have been obtained at different temperatures and pressures. The kinetic parameters were also determined in calorimetric and chemical experiments.

INTRODUCTION

During the steam injection tests, many physical changes of oil, water, and rock take place in the reservoir, but in in-situ combustion processes, physical changes as well as chemical reactions occur simultaneously or sequentially in the vicinity of the combustion front in the formation. It is generally believed that the latter process should be controlled by chemical reactions. The oxidations, including combustion of crude oil in place, are exothermic reactions, but cracking reactions could be endothermic. There might have been many catalytic and noncatalytic reaction processes taking place in the reservoir. It is impossible however to assume simply that crude has only a few pseudocomponents; some of them were involved in this "combustion" (oxidation is more correct); and it only yielded CO_2 and CO gases during the process. Actually, the kinetics of the reactions are very complex so that heat generated in the process could not be represented with the following equations:

(1) $Q = R_c \cdot DH_c$[1]

or

$Q = R_r \cdot DH_rxn$[2,3]

It is difficult to obtain a correct expression by using a theory to get Rc (or Rr) and Hc (or ΔH_rxn) for many kinds of crude oils from different fields, even for a pure alkyl compound. The ΔHc is the combustion heat of the crude oil studied. In fact, the combustion process in the in-situ operation or in the combustion tube tests simultaneously involves many kinds of oxidations. Thus the ΔH_rxn expression is correct, but the data should be obtained from experimental work. Accordingly, the chemical simulation of in-situ combustion processes should be developed.

The goals of the study presented here are to investigate the thermokinetics of oxidation of heavy oil from the Nanyang field; to study an alkyl compound (n-Dotriacontane as a model compound of oil), stearic acid, and octadecanol; and to identify the kinetic parameters of reactions. Some of the results from this approach could be used as an indispensable part of the feasibility study for a heavy oil project of this field. The data are useful to generate the heat source term in the energy balance equation of the numerical combustion model. The results from the studies should also be of help to control the operation of in-situ combustion in the field.

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* This project is a part of the Canadian-Chinese Cooperative Research performed by Z.L. Zhang in Beijing and by L. G. Hepler in Edmonton.

** Y.F. Liu carried out a part of experiments for this study.

EXPERIMENTAL

Materials

The crude oil studied was obtained from the Nanyang oil field. The oil gravity ranges from 0.938 to 0.996 g/cm (25°C). The viscosity of the degassed crude oil is from 111 to 7515 cp at 50°C. The crude oil contains paraffin of 4.6–20.1% on a dry-weight basis, and the bitumen contents is 11.1–37.0%. The asphaltene in the bitumen, precipitated by heptane, is negligible. The acid number of the crude oil is about 3.0 mg KOH/g.

The n-dotriacotane, stearic acid, and octadeconal used here were commercial products without further purification.

The commercial sands (quartz), treated up to 1200°C, were used as the reservoir rock for study.

APPARATUS

Carbon, hydrogen, and nitrogen were analyzed by using an Elemental Analyzer (model 1102 from Carlo, Erba, Italy). An apparatus for the investigation of oxidation was built. Figure 1 shows the flow diagram of the apparatus.

Thermal analyses presented in Figures 2 and 3, show the curves of TG and DTA in dynamic air and Ar purge respectively. A thermal balance and differential thermal analysis as a combined technique were used in this study. It was easy to identify the oxidation behavior of the crude oils and to distinguish each step of the process. It was better this way than the two techniques used separately. Figure 2 presents typical curves of TG and DTA of crude oil in the dynamic air purge. A distillation process occurred mainly around 100°C, because an endothermic peak on the curve of DTA and a litter mass loss exhibited on TG curve can be seen at this temperature region. Low-Temperature Oxidation (LTO) of the sample was taking place in the temperature range of 280°C–395°C. An exothermic thermgram presented on a DTA curve and a distinct mass loss occurred (it could be some kind of light oil distillate) in this region. After this step, a great exothermic effect and a large mass loss appeared in the 410–520°C range. It should have been the combustion (including crude oil being cracked simultaneously) of the sample. There are some differences between Figures 2 and 3; the curve shown in Figure 3 was taken in Ar purge, the cracking reactions should result in much more oxidations. In the Figure 2, however, there should be some residual air in that system.

Figures 4–7 present typical calorimetric curves of oxidation of crude oil, n-Cotriacotane, stearic acid, and Octadecanol. After a treatment with the results obtained at 150°C, the heat generation in power (not energy) at the beginning of oil oxidation can be expressed with the following relationship:

$$(2)\quad W(t) = 74.5 * P(O_2) * E^{0.7}$$

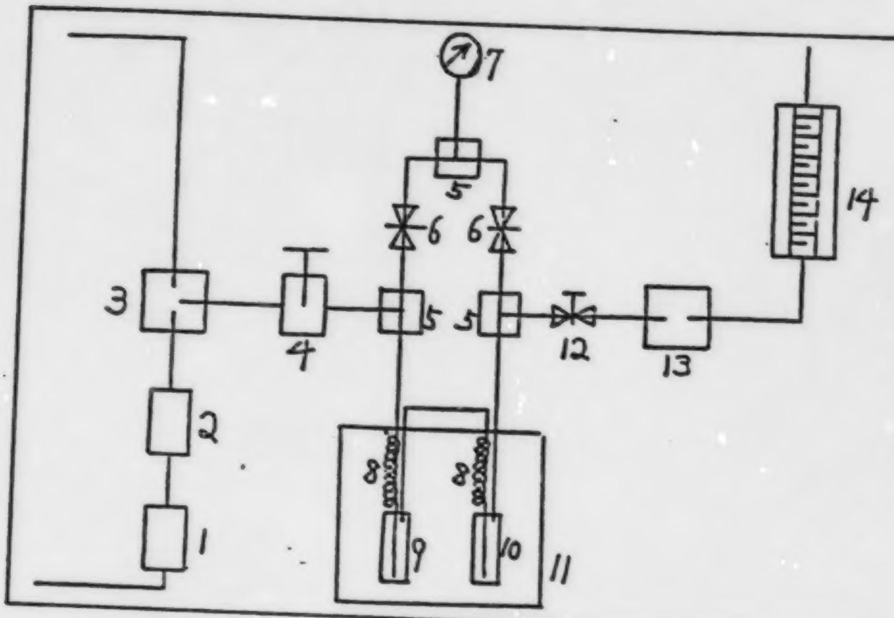
where $P(O_2)$ is partial pressure of oxygen (in atmosphere). If oxygen in the flowing gas was controlled at 48.94% and pressure of 1.50 atm, and several treatments were taken as mentioned above, the reaction constant was found:

$$(3)\quad \mathrm{Ln}\, K_r = 22.59 - 7679 * (1/T)$$

with a correlation coefficient $r = 0.985$. Kr is the reaction constant in the oxidation of crude oil and T is the temperature in °K.

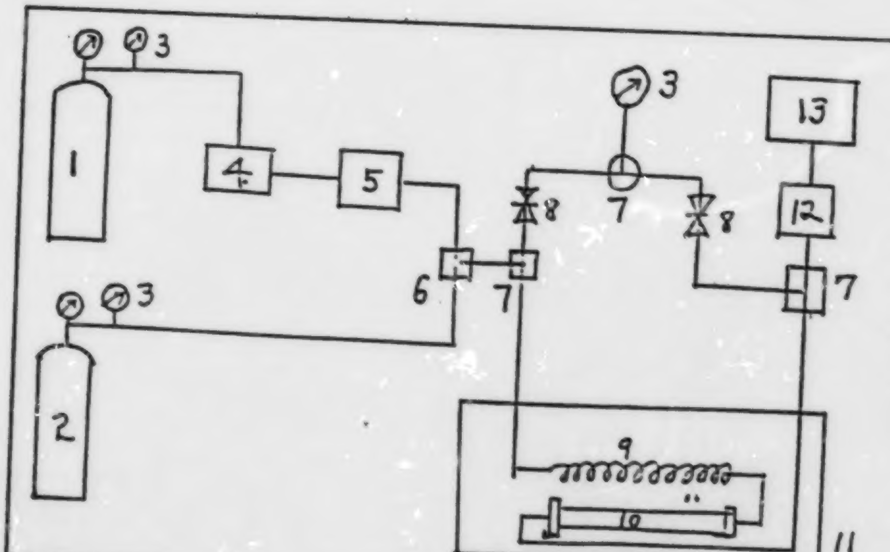
The activation energy of 63.8 kj/g mol and the Arrhenius constant of $6.47 * 10^9$ were obtained here. The results are in good agreement with those from several studies in reference (5).

An increase in reaction rate with an increase in oxygen content shown in Figure 5 was observed here.



1. Absorbing tube of CO
2. Absorbing tube of HO
3. 3-way valve
4. Pressure stabilizer
5. 3-way connection
6. Cut-off valve
7. Pressure meter
8. Pre-heating pipe
9. Sample cell
10. Reference cell
11. Calorimeter
12. Regulating valve
13. Flow rate stabilizer
14. Flow meter

Figure 1a. Calorimetric system of thermokinetic investigation for chemical simulation.



1. Oxygen
2. Nitrogen
3. Pressure meter
4. Oxygen purifier
5. Pressure stablilizer
6. 3-way valve
7. 3-way connection
8. Cut-off valve
9. Pre-heating pipe
10. Reaction tube
11. Thermostat
12. Cooling pipe
13. Flowing rate controlling & measuring system and absorbing tube of acid gas product

Figure 1b. Investigation system for chemical kinetics.

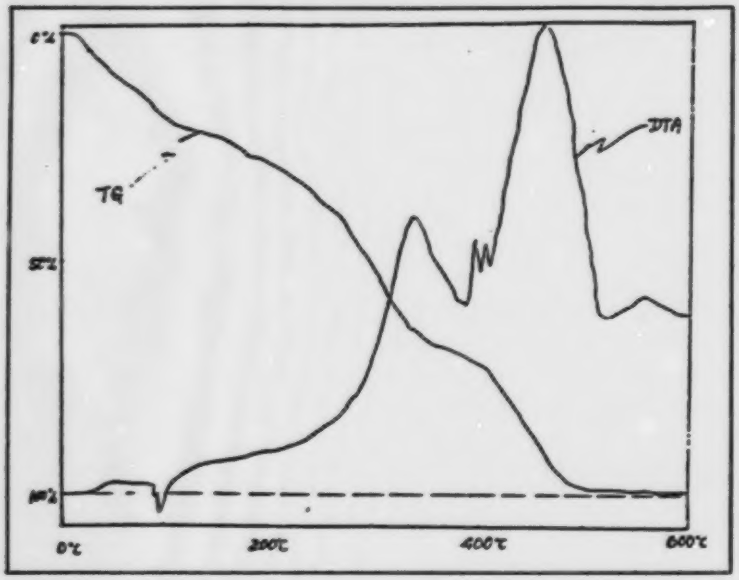


Figure 2. TG and DTA curves of crude oil in dynamic air purge.

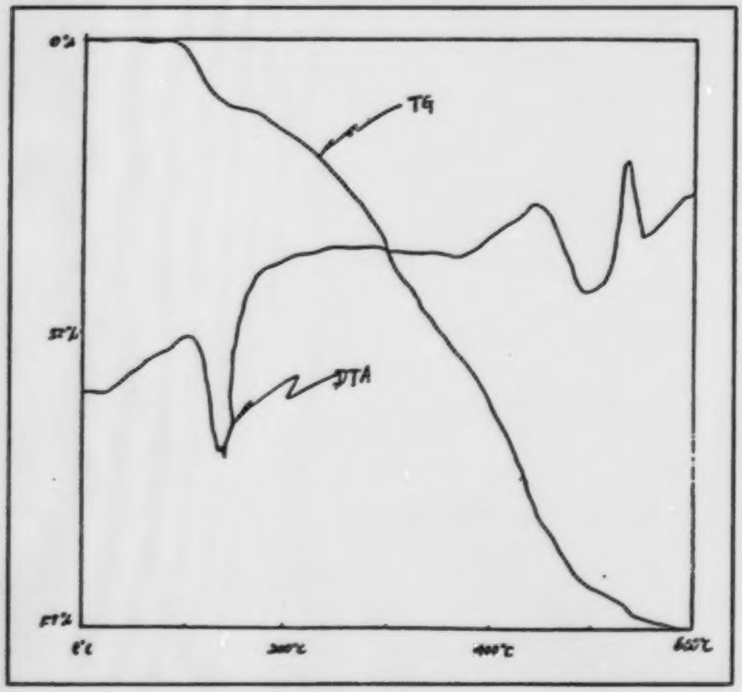


Figure 3. TG and DTA curves of crude oil in dynamic Ar purge.

The crude oil oxidation is a complicated process, especially in the reservoir, in which the catalytic reactions may occur. Consequently, consideration of simple chemical reaction mechanisms or some basic processes should not be possible in this situation. Figure 7 shows the oxidation of n-Dotriacontane, stearic acid, and octadecanol. They are different from each other, including crude oil. All of the results obtained above indicate that oxidations of crude oil are very complex. Other experiments such as potentiometer titration of acidic products in the oxidation also proved this. The typical curves of potentiometer titration of acidic products in the oxidation crude oil and n-Dotriacontane are shown in Figures 8 and 9. The titration curve of crude oil or pure $C_{32}H_{66}$ indicates obviously that point of inflection could be used for end point. In other words, the slope is satisfactory. The shapes of titration curves of their oxidation products are quite different from each other, indicating that there are some differences, such as acidity, amongst them. Therefore, the chemical characters of crude oils could extremely affect the oxidation of these crudes and the heat generated. The results of analyses of gas products are shown in Table 2. The contents of these products changed with the oxidation process undergoing. This also indicates that the process is very complex.

Now, it is quite clear that the system of in-situ combustion process is not only associated with physical changes, but also with chemical reactions. There are many complex mechanisms in the in-situ combustion process.

Several authors, such as A.L. Benham et al.[7-9] reported their research works. Accordingly, the

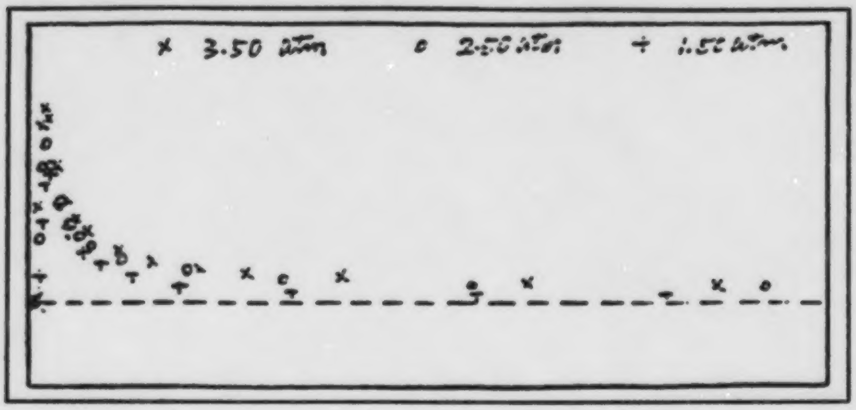


Figure 4. Thermodynamic curves of oxidation of crude oil at different pressures.

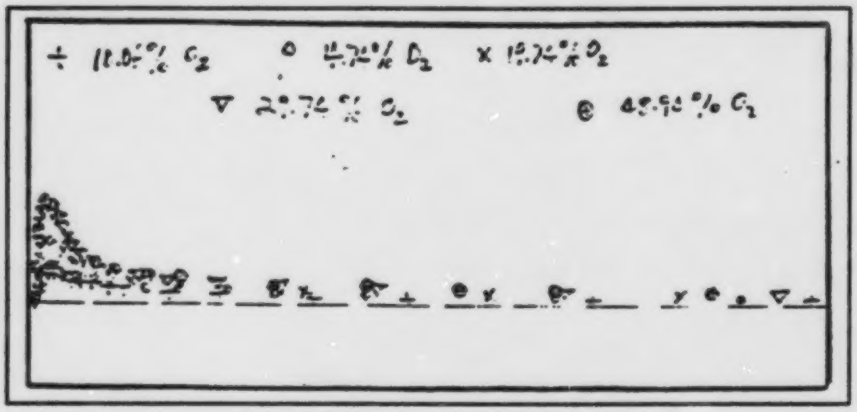


Figure 5. Thermodynamic curves of oxidation of crude oil with different contents of oxygen.

chemical reaction may be represented by the stoichiometric equation:

(4) $CH_m + [(2m + 1)/(2m + 2) + n/4]\, O_2 \rightarrow$
$m/(1 + m)\, CO_2 + 1/(1 + m)\, CO + (m/2)\, H_2O$

where n is the atomic hydrogen-to-carbon ratio of the fuel and m is the molar CO_2/CO ratio in the oxidation products. The reaction rate can be described in[10,11]

(5) $Rr = k \cdot (PO_2)^p \cdot C^q$

where PO_2 is the partial pressure of oxygen and p,q are the reaction orders.

The heat generation, as mentioned previously should be described as:

(6) $Q = DH_r xn \cdot Rr$

where $\Delta H_r xn$ is the heat of the reaction concerned.

It is true that the $\Delta H_r xn$ depends on the different kinds of reactions. Therefore, further investigation of reaction kinetics of in-situ combustion should be done in theory and experiments. It is possible that better results like these parameters are acquired directly from experiments.[12–14] In this case, many key parameters or their relationship could be seized from experiments in chemical simulation. The heat generation q(t) (in thermal power w(t)), obtained from calorimetric determinations, may be expressed as a function of different parameters, as:

(7) $q = f\,(T, Po, Ci \ldots, t)$

From the reasons mentioned above, the chemical simulation should be done to at least support the numerical simulation works and to help the operation of in-situ combustion in field.

CONCLUSIONS

1. A thermokinetical model has been introduced and presented in this paper. Several important parameters corresponding to in-situ combustion processes could be obtained from the said simulation.
2. The results of data analysis indicated that oil properties, oxygen contents as well as operation temperature and pressure significantly affect the process of in-situ combustion.

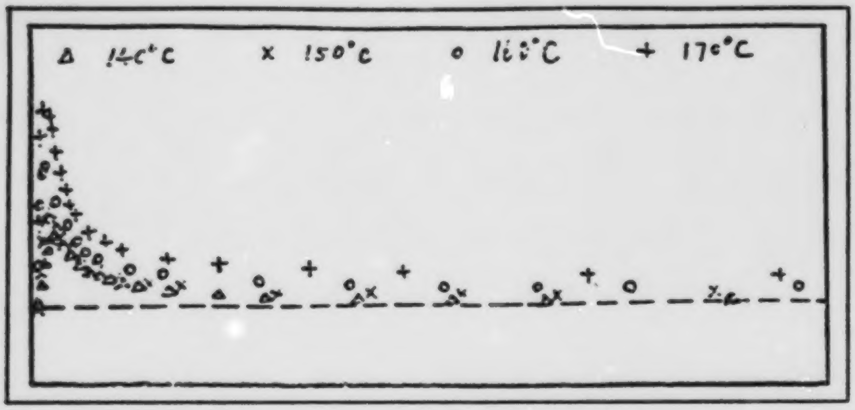


Figure 6. Thermodynamic curves of oxidation of crude oil at different temperatures.

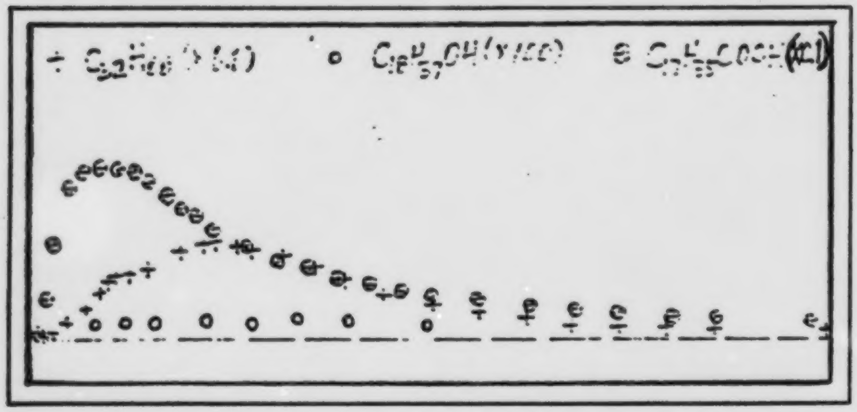


Figure 7. Thermodynamic curves of oxidation of CH, CH OH, and CHCOOH in dynamic air (19.74% O) purge at 150°C.

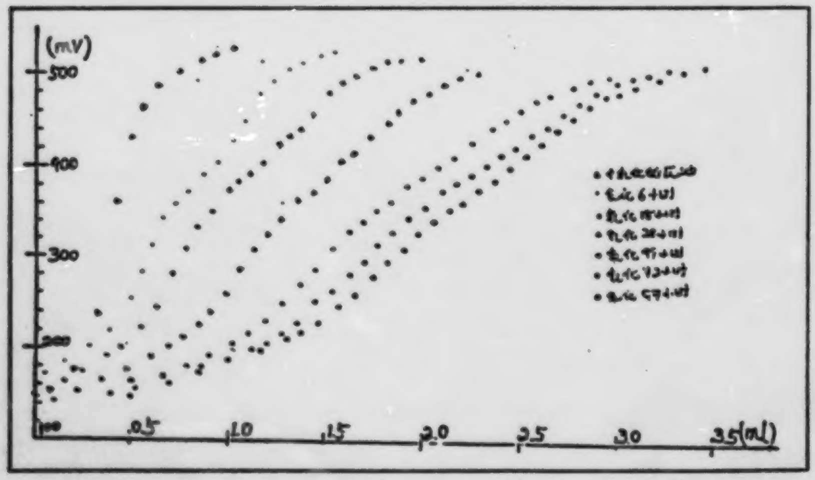


Figure 8. Potentiometer titration curves of oxidation products of crude oil.

3. The chemical simulation of the in-situ combustion process should help physical and numerical reservoir simulations. From which, the results could further assist the field research and operation.

ACKNOWLEDGEMENTS

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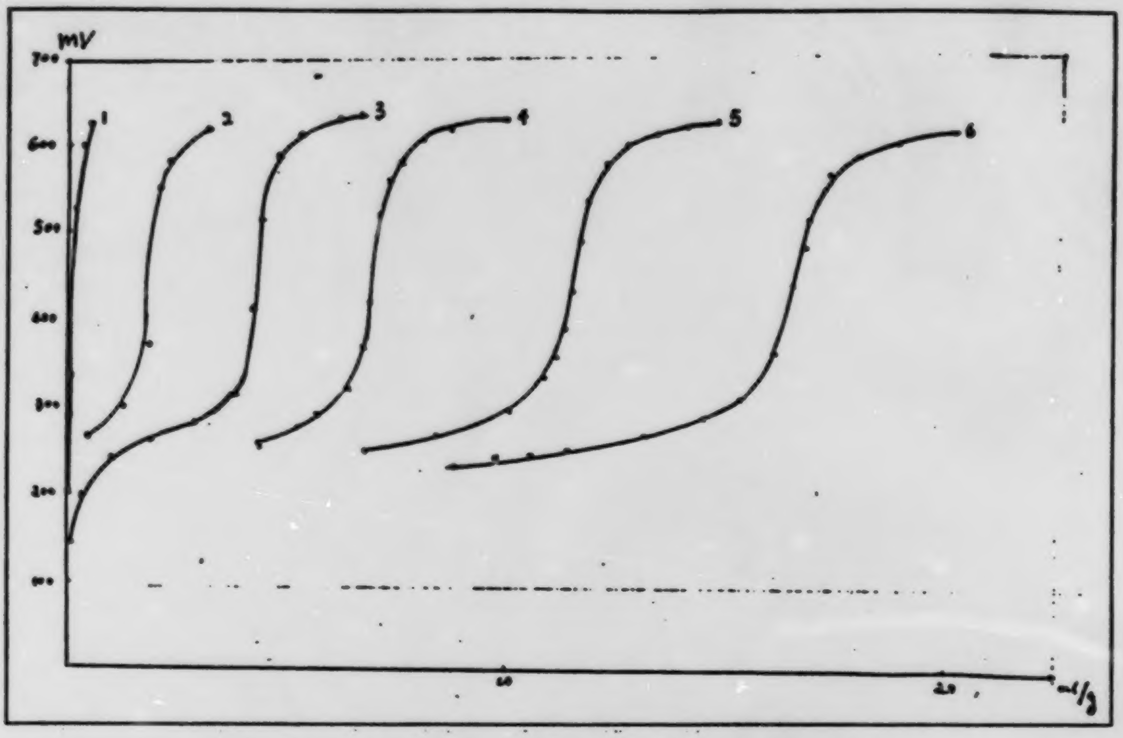

Figure 9. Potentiometer titration cruves of oxidation products of $C_{32}H_{66}$.

Table 2. Gas products analyses

Time (hr.)	CO_2 (%)	CO (%)	O_2 (%)	N_2 (%)	CH_4 (%)	H_2O (%)
9.72	2.88	6.26	2.31	52.79	0.73	35.01
18.70	12.02	1.06	2.38	79.10	0.61	4.83
24.23	1.71	1.52	13.92	70.81	0.00	12.75
38.18	15.12	0.82	2.85	60.87	0.67	19.51

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LABORATORY AND FIELD STUDIES OF ADDING PETROLEUM SULPHONATE TO CYCLIC STEAM INJECTION WELLS

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ABSTRACT

This paper presents the laboratory and field studies of using Karamay Petroleum Sulfonate (KPS) as additives for cyclic steam injection wells in the Karamay oil field. The said chemical is thermal stable at high temperature, and could reduce the oil-water interfacial tension effectively in reservoirs. As a result, the liquids tend to form larger droplets, which can be emulsified as an oil-in-water emulsion. In this case, the oil viscosity might be reduced 10 to 20 times, oil mobility could be significantly improved, and rock wettability would be changed to such condition, which is favourable for oil flow. From high temperature flooding tests, the results indicated that steam injection with KPS could not only increase 5.1% of oil recovery, but also improve oil-steam ratio notably.

During the field tests, KPS was added with steam into ten wells for cyclic operation. In which, having the success ratio of 80%, it achieved 537 tonnes of incremental oil per well. This corresponds to about 126 tonnes of such oil production with a tonne of commercial grade KPS injection.

INTRODUCTION

The steam stimulation technique has been proved to be a feasible way for shallow heavy oil development in Xinjiang. However, the serious decreases of oil rate in cyclic operation often resulted in project shutdown due to economical reasons. Thus, to maintain the oil rates cycle by cycle, increase total oil production, and conduct economical steaming operation in this field were therefore investigated.

In the mid-1960s, Muggee and Gilson presented a method of injecting demulsified agents with steam for heavy oil recovery in order to increase oil production and to decrease operating costs. During the early 1980s, Blain Jr. and Adkins performed several field tests by injecting a nonionic thin film spreading agent (TFSA) into reservoirs for steaming operation. As a result, a great quantity of incremental oil was obtained, also, its aftereffect provided more oil for the next cycle production as well. This is due to an interfacial action by the said agent (nonionic surfactant), which forms a film to adhere to the water-oil intersurface. As a consequence, it easily creates oil droplets and breaks water-in-oil emulsions. No wonder the oil wells productivity and recovery are improved.

As mentioned above, the KPS holds certain properties, which includes good thermal stability. These surfactants injected into reservoirs with steam should solve some problems and increase cyclic oil production. Therefore, several heavy oil wells at District 9 were selected for KPS injection tests. So far, encouraging results have been obtained.

This paper presents the results of laboratory tests and field practice by using KPS to improve cyclic oil production for thermal oil recovery.

LABORATORY STUDIES

The laboratory studies consisted of six experiments and are discussed as follows. Two types of KPS (KPS-1, KPS-2) were used for these tests, and TRS 10-80 imported from the U.S. was also utilized for the comparing results. The properties of the said surfactants are shown in Table 1.

Table 1. Sulfonate surfactant property

Surfactant	Active content (%)	Oil content (%)	Salt content (%)
KPS-1	86.63	8.67	4.4
KPS-2	90.5	4.89	3.71
KPS-10	90.1		

1. Thermal Stability Experiment

The objective of this experiment was to evaluate the thermal stability of chemicals. The results are generally represented as half-time. The longer half-time of a chemical, the better the thermostable performance is.

The results of testing KPS-1, KPS-2, and TRS 10-80 are given in Table 2 and Figure 1. In these, the thermal stability of KPS-1 and KPS-2 is better than that of TRS 10-80, indicating the former two chemicals should meet the thermostable requirement for cyclic steam injection.

Table 2. Surfactant thermostable performances

Surfactant	Half-life, days
KPS-1	33
KPS-2	14
KPS-10	0.9

2. Interfacial Tension Tests

A dominant mechanism of sulfonate surfactants used as steam soaking additives is to reduce the interfacial tension between oil and water in the reservoir. Our study was therefore to measure this important parameter. The oil produced from a pool in District 9 and distilled water were utilized for this experiment. The interfacial tension between solutions with different concentration of KPS-1, KPS-2, and oil were measured at 30°C. The results shown in Figure 2 indicate that interfacial tensions were reduced with increasing sulfonate surfactant concentration.

3. Changing Wettability Experiment

Changing wettability is often observed from water imbibition tests. Core samples obtained from reservoir rocks, that are preferentially water-wet (hydrophilic), would produce more oil by water displacement. Where the rocks are preferentially oil-wet (hydrophobic), there would be less oil drained out with low displacement efficiency. The changing wettability tests using different concentrations of KPS-1 were measured at 60°C and 90°C. The results indicate that at the same temperature, increasing KPS-1 concentration could increase the oil drained from the cores. While at the same KPS-1 concentration, higher temperatures would increase oil output by water imbibition. This suggests that KPS is certainly able to change rock-surface wettability from oil-wet to water-wet, or from a less hydrophilic to a more hydrophilic condition.

4. Static Adsorption Experiment

As is known to all, injection of KPS into a reservoir would result in a loss of certain amounts of surfactant solution when it contacted with rock surface. Table 3 shows the results of static adsorption experiments for different concentration of KPS with a core surface at 25°C. From the

Table 3. Static adsorptions for different concentration of KPS at the core surface

KPS concentration (pm)	Amount adsorbed mg (KPS)/g(sand)
7144	19.7
1334	6.6
638	3.4
406	2.7
290	2.5
116	1.2
87	0.5

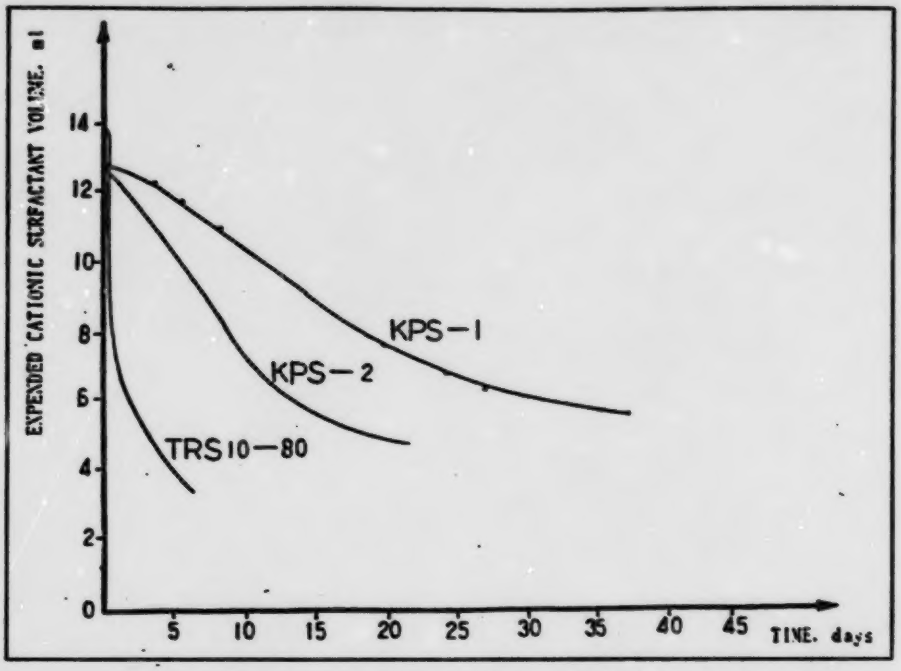

Figure 1. V(c) versus t for KPS-1, KPS-2, and TRS 10-80 at 250°C.

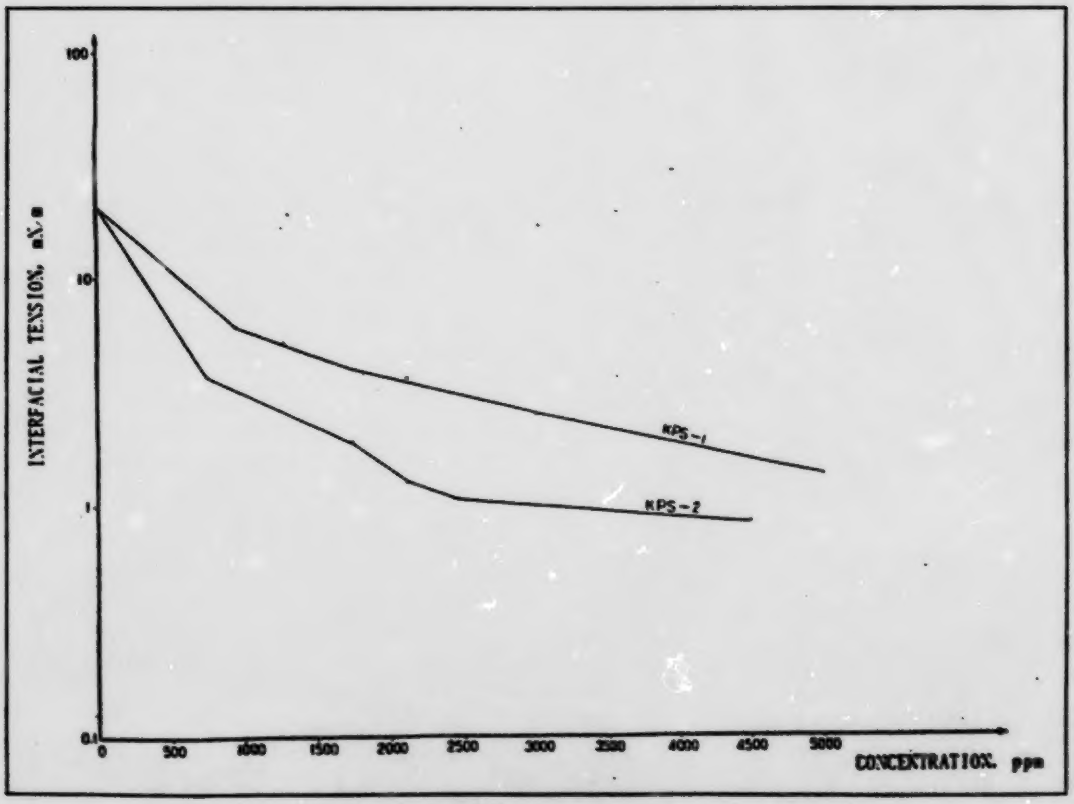

Figure 2. Different concentration of KPS versus interfacial of oil.

data, the more surfactant solution lost is related to an increase of its concentration. However, the amount of adsorption on the reservoir rocks from District 9 is insignificant even if at higher concentration. In addition, the loss of surfactant solution decreased with the increase of temperature (above 250°C). Thus, the adsorption during field practice may not be a problem.

5. Oil-Water Emulsion Tests

When a surfactant is added into an oil-water system, oil and water will be emulsified to form either water in oil emulsion or oil in water emulsions. The viscosity of the former is much higher than that of oil, but the viscosity of the latter is much lower. Thus, adding surfactant to form oil in water emulsions could improve oil mobility in the reservoir. The oil produced from wells Jiuqian-1 and Jiuqian-7 in District-9 was used for this study. The results shown in Table 4 indicate that KPS solution added into an oil-water system would develop oil in water emulsions with a low system viscosity.

6. Core Flood Tests at High Temperature

This cooperative study was carried out with the Research Institute of Petroleum Exploration and Development in Beijing. The mixed oil produced from District 9 was used after filtration and dewater processes. The cleaned, unconsolidated cores from well J-224 were packed in a stainless tube with a diameter of 2.5 cm and a length of 35 cm. The loosened rocks in the tube exhibited porosity of 37% and horizontal permeability of 2.3 μm^2. The amount of steam, which is equivalent of 0.5 pv of water, was injected into the tube with a KPS solution (1000 ppm) for oil displacement. The results gave an incremental oil recovery of 5.4% for the test compared to that without the said surfactants added. This indicates that these KPS agents are useful to accelerate early oil production and increase oil-steam ratio during steam stimulation.

It is concluded from the evidence of laboratory tests that KPS surfactants could be used as additives for thermal oil recovery.

FIELD TESTS

Criteria of Well Selection

1. Wells should have had at least two complete cycles of steam stimulation, in which, the production performance behaved in a normal way, i.e., the oil production from the latter cycle is less than that from the previous one.
2. The pay zone in wells should be as similar as possible in order to have nearly the same testing conditions.
3. Wells must be in good condition, with no mechanical or sandoff problems.
4. The selected wells should approach the end of a complete cycle. So the test could be conducted at the beginning of the next cycle.
5. The chosen wells should have no hydraulic communication with others in a reservoir.
6. Steam quality as well as injection rate before and

Table 4. Emulsifying experiment results with KPS fluid and oil

Well	Commercial KPS concentration (ppm)	Oil/water ratio (vol/vol)	Oil viscosity (MPa·s)	Temperature (°C)	Emulsion viscosity (MPa·s)
Jiu-Qian-1	3000	60/40	1720	24	65
Jiu-Qian-1	3000	70/30	1720	24	80
Jiu-Qian-7	3000	60/40	2600	23.8	60
Jiu-Qian-7	3000	70/30	2600	23.8	85

during the tests should be consistent in these chosen wells.

Based on these requirements or conditions, ten wells located in District 9(1), 9(3), and 9(4) were selected for field tests. The details of well data are listed in Table 5. The reservoir sequence of these ten wells are all in the Qian formation (late Jurassic age) with depth (middle horizon) of 200 to 300 meters. The KPS surfactants were added into nine wells with steam during the third cycle operation, except for well 9153, in which the surfactant was injected during the fourth cycle. Four different surfactants, namely KPS-1, KPS-3, KPS-4, and XPS-1, were used in the mentioned ten wells, the physical properties of these surfactants are shown in Table 6.

Operation Procedures

The operation procedures for surfactants injection with steam are simple and as follows:

1. Lift pump for workover, and check whether the sand plug occurred in the wellbore. If so, remove it before running the tubing down.
2. In general, the 10% KPS solution is prepared in a tank. In which, KPS is completely dissolved in water by pump circulation to make the required volume for injection.
3. By pumping the KPS solution into the reservoir at a rate of 10 m^3/h, the injection pressure is controlled below the formation fracturing pressure.
4. After pumping, inject 3 to 5 m^3 of water to displace KPS fluid into the formation.
5. Inject steam at the required rate.
6. Shut in the well and soak it for a designate period.
7. Put well on production.

Table 5. Original data for testing wells

Well	Horizon	Net pay thickness (m)	Porosity (%)	Average permeability (μm2)	Oil saturation (%)	Oil density (g/cm^3)	Oil viscosity (mPa·s, 30°C)
9153	J3	11	29	1.406	69	0.9345	7140#
93052	J3	11.5	31.9	3.569	60	0.9319	1584.9
93144	J3	5.2	32.7	3.961	72	0.9237	1740
93233	J3	11	30.8	2.479	60	0.9337	6510.6#
93124	J3	9.1	32	3.218	57	0.9255	1280.36
93246	J3	14.1	31.2	2.844	51	0.9365	1657.04
93079	J3	10.0	28.3	1.176	56	0.9355	2476.99
94013	J3	10.4	28.3	1.173	62	0.9325	2848.89
94153	J3	15.1	30.7	2.283	63	0.9328	9147.7#

Table 6. Sulfonate surfactants properties

Surfactant	Active content (%)	Mineral content (%)	Inorganic salt content (%)	Volatile component (%)
KPS-1	33	31	4	26
KPS-3	15	13	11	45
KPS-4	25	32	5.5	36
XPS-1	30	40	3.5	25

Index for Testing Results Evaluation

The testing results from ten wells are listed in Table 7. For evaluation of such data, the following indexes were used to decide whether KPS surfactants were effective to improve oil producing performance in these wells (Table 8).

1. Total oil production during the testing cycle must be greater than or equal to that from the previous cycle.
2. Average oil production during the testing cycle should be greater than or equal to that from the previous cycle.
3. Peak oil production (monthly average peak value of daily oil production) in the testing cycle must be greater than or equal to that from the preceding cycle.

DISCUSSIONS OF FIELD TESTING RESULTS

The comparison and evaluation of the testing results from 10 wells in the Karamay field are presented in Table 8. Oil producing history for individual wells is shown in Figures 4 to 13.

1. Complete field tests have been carried out on six wells. The results from the other four wells,

Table 7. Results from 10 wells and main factors for cyclic steam injection

Well		Cyclic prod. (t)	Peak prod. (t/d)	Average daily (t)	Cyclic steam inj. (t)	Steam temp. at (°C)	Steam quality (%)	Steam inj. (MPa)	KPS require. (t)
94013	preceding cycle	445	3.2	3.3	1564	217	60	5.5	
	testing cycle	611	1.0	3.0	2244	210	64	4.5	4.5
94153	preceding cycle	445	3.2	3.1	1564	217	60	5.5	
	testing cycle	279	4.8	2.5	2215	200	60	4.5	4.5
9153	preceding cycle	877	7.1	4.2	3443	190	63	3.5	
	testing cycle	262	5.9	4.4	1558	272#	72	4.0	4.9
93144	preceding cycle	386	3.4	2.6	1541		65	4.5	
	testing cycle	1066	8.1	5.2	1572	180	72	3.5	4.0
93052	preceding cycle	814	7.5	4.6	1695		72	5.8	
	testing cycle	2292	14.9	6.0	1562	200	71	3.8	4.3
93079	preceding cycle	670	4.5	3.7	1787	224	70	4.3	
	testing cycle	998	8.6	4.9	2223	224	67	4.4	4.2
93080	preceding cycle	921	6.2	5.4	2110	200	70	5.3	
	testing cycle	851	6.8	4.1	1895	190	67	3.6	4.0
93233	preceding cycle	730	7.6	4.4	2193	220	67	4.2	
	testing cycle	730	3.8	2.6	2759	250	71	4.6	4.0
93246	preceding cycle	1386	14.1	5.7	1897	225	71	4.5	
	testing cycle	792	6.6	4.7	1950	150	65	3.0	7.9
93124	preceding cycle	1089	9.6	5.1	1977	184	70	6.4	
	testing cycle	309	2.4	1.3		187	70	1.8	5.0

Table 8. Evaluation for 10 testing wells results

Well	District	Cyclic decline rate (%)	Cyclic production with KPS (t)	Cyclic production without KPS estimated by the decline rate (t)	Cyclic incremental oil production (t)	Evaluation of results	Note
94013	9-4+	42	611	246	347	valid	continue for testing
94153		42	877	162	715	valid	continue for testing
9153		31	1262	1151	111	valid	off test
93144		20	1066	309	757	valid	off test
93052		20	2292	651	1641	valid	off test
93079		20	998	536	462	valid	continue for testing
93233		20	730	584	146	valid	off test
93080		20	852	733	118	valid	continue for testing
Total incremental production for 3 effective wells is 4297 t							
93124		20	309	871		no valid	for test
93246		20	792	1190	347	no valid	for test

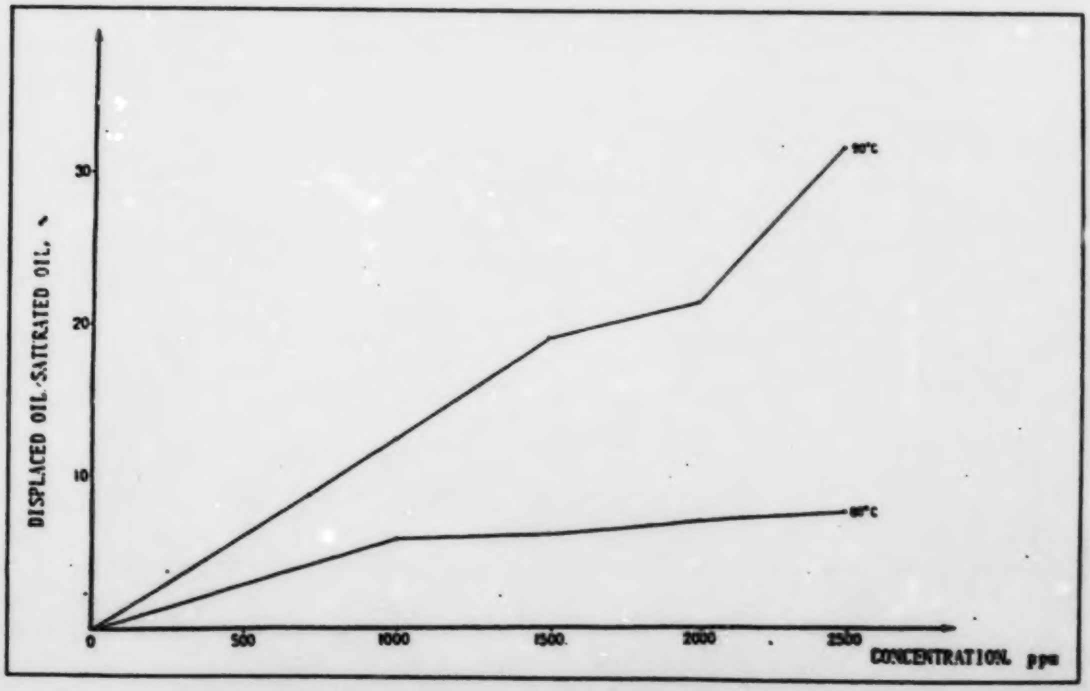

Figure 3. Imbibition displacement curves for different concentration of KPS.

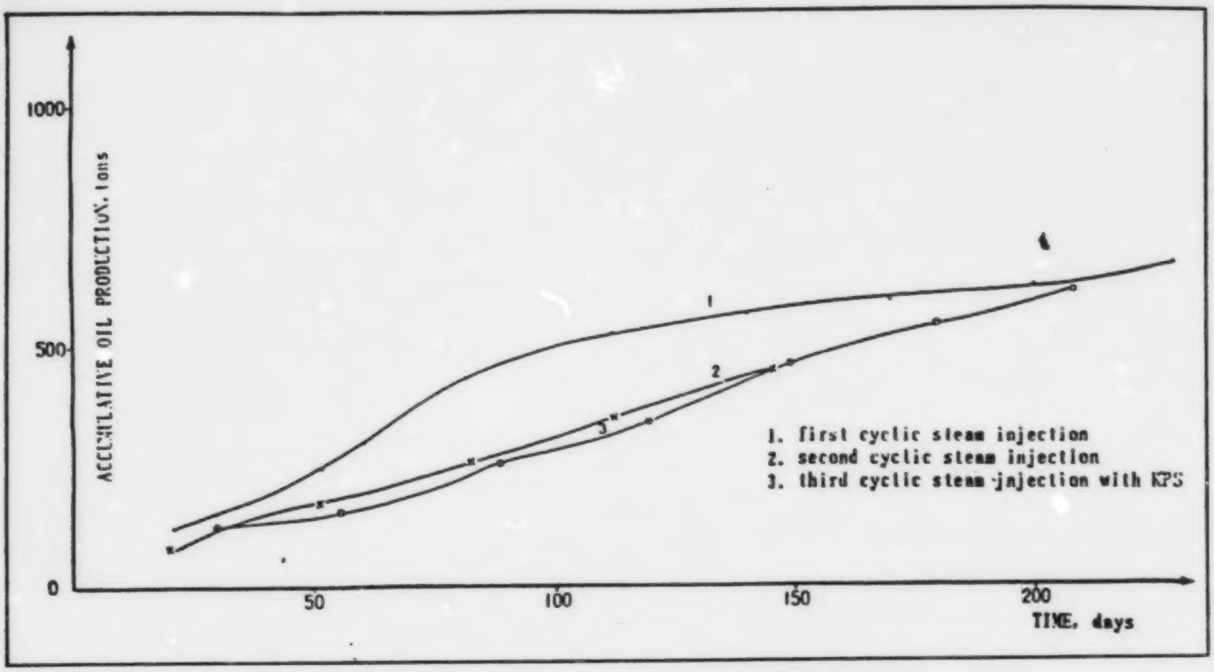

Figure 4. Accumulative production history for Well 94013.

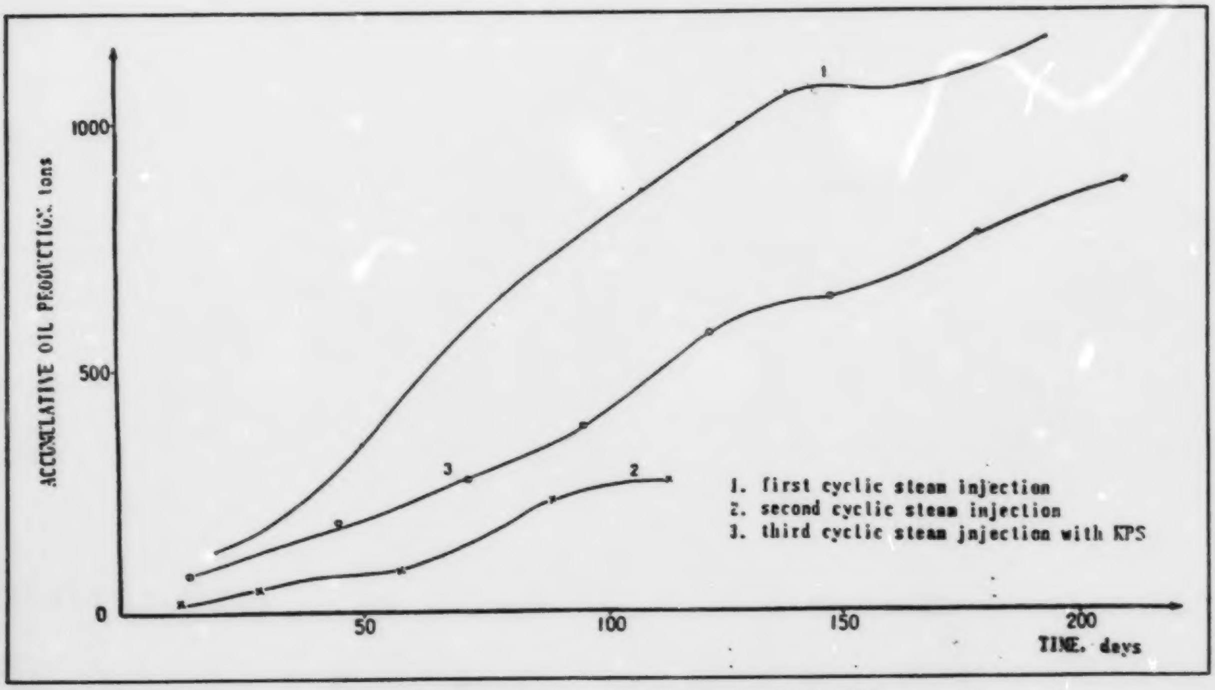

Figure 5. Accumulative production history for Well 94153.

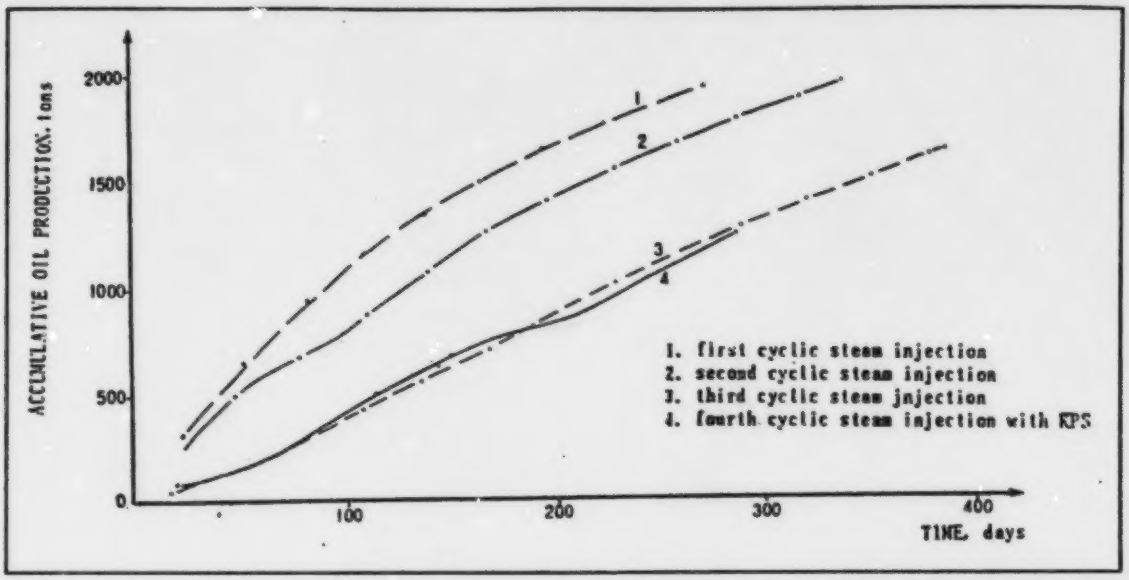

Figure 6. Accumulative production history for Well 9153.

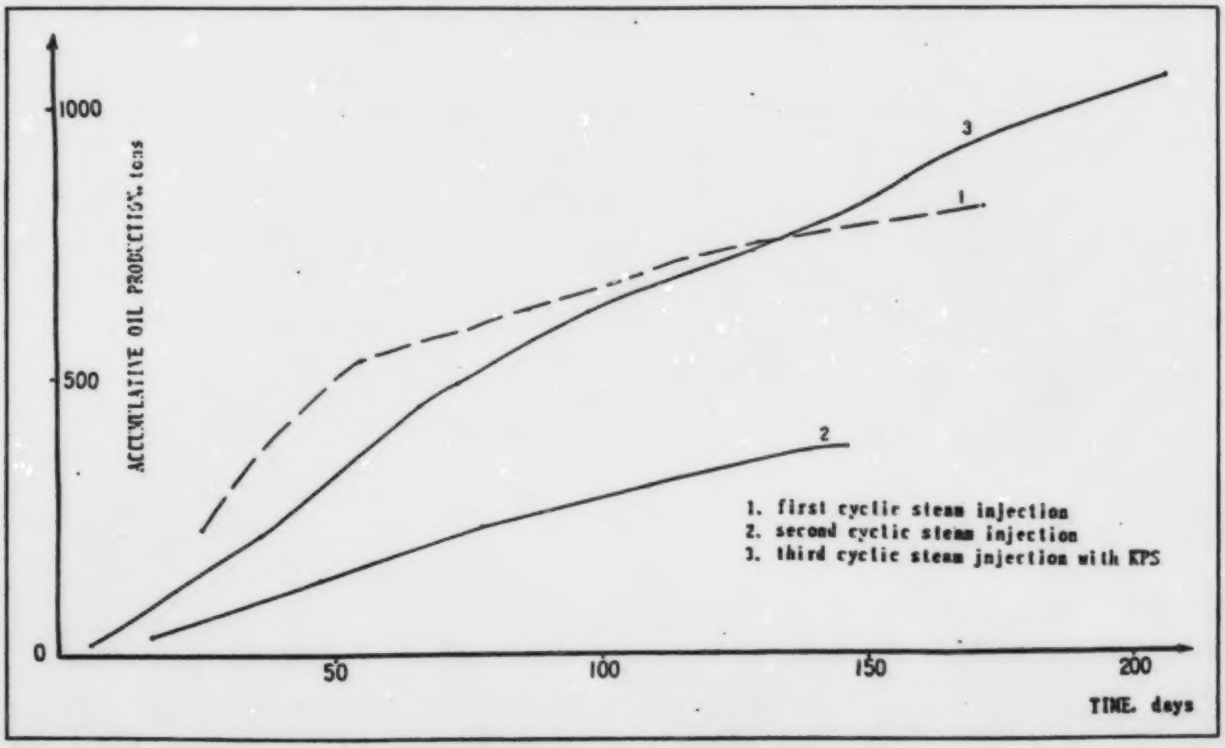

Figure 7. Accumulative production history for Well 93144.

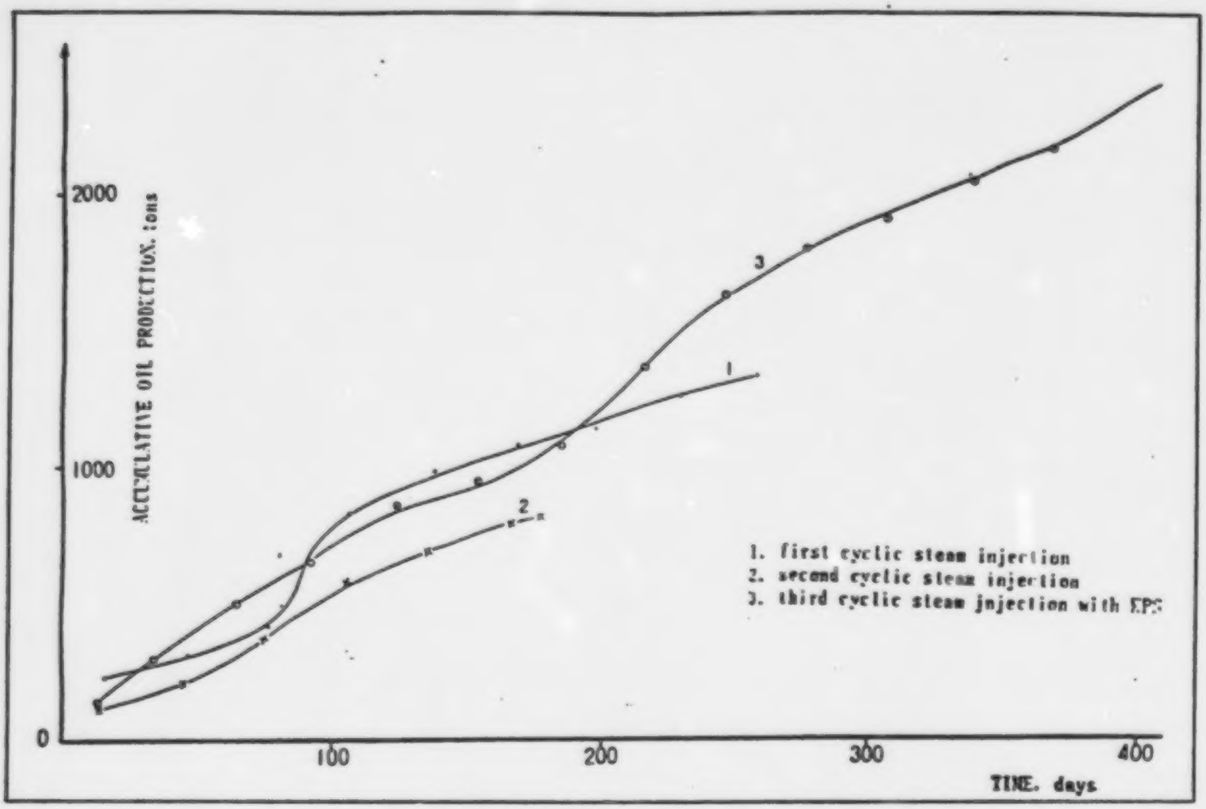

Figure 8. Accumulative production history for Well 93052.

which are still under testing, are only available dated to the end of July 1990. According to reference 4, the effect of adding KPS surfactant for steam stimulation would not only improve oil production in that testing cycle, but also increase oil rate in the succeeding one. Therefore, the final incremental oil production on these four wells must be greater than the currently available figures.

2. During multi-cycle steam stimulation, normally, oil production from a cycle is lower than that from the preceding one. The cyclic decline rate varies with the oil and reservoir properties. According to a summary of the collected data from oil fields in Xinjing, the average oil decline rates from cycle to cycle in wells of District 9 are as follows. This information will be used for performance comparison.

District 9(4)	42%	from second to third cycle
District 9(1)	31%	from third to fourth cycle
District 9(3)	20%	from second to third cycle

3. An analysis of cyclic cumulative oil, peak and average daily oil production from these ten wells indicates that oil production from eight wells were effectively improved due to the use of KPS surfactants. Thus the success ratio of these tests is 80%. Total incremental oil from eight wells was 4,297 tonnes, that is about 126 tonnes of oil for a tonne of commercial KPS surfactant (the active component was about 30%). If these calculations are applied for ten wells, in which, 47 tonnes of surfactants were injected. This resulted in 91.5 tonnes of the incremental oil for a tonne of KPS surfactant, and the average oil increase per well was 430 tonnes.

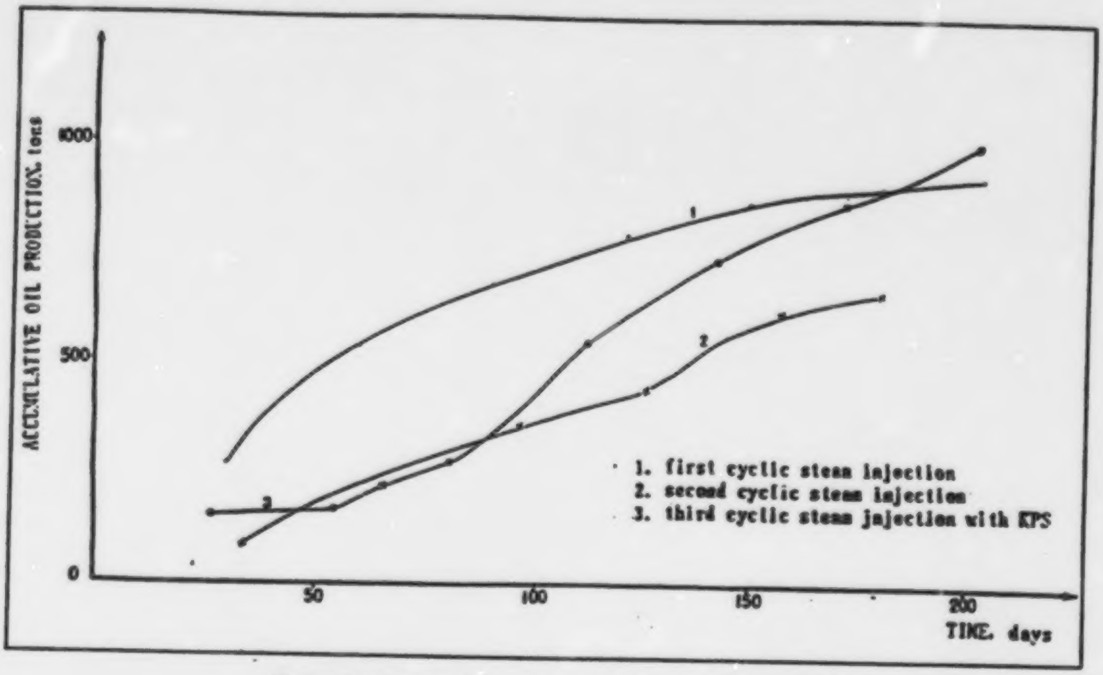

Figure 9. Accumulative production history for Well 93079.

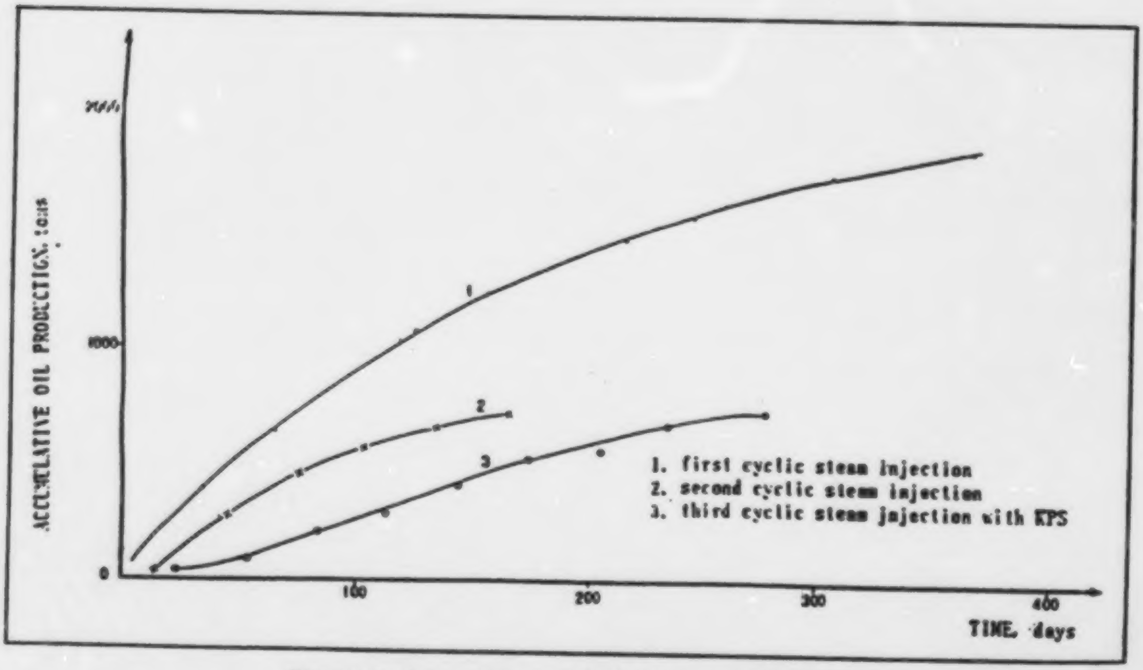

Figure 10. Accumulative production history for Well 93233.

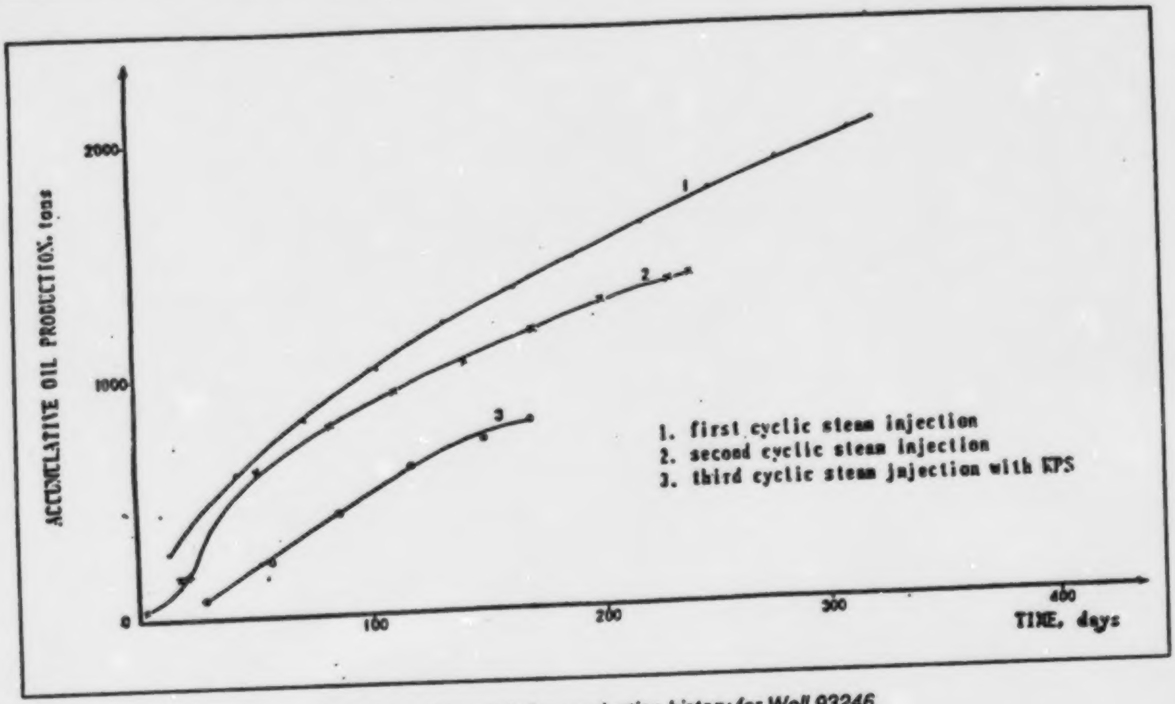

Figure 11. Accumulative production history for Well 93246.

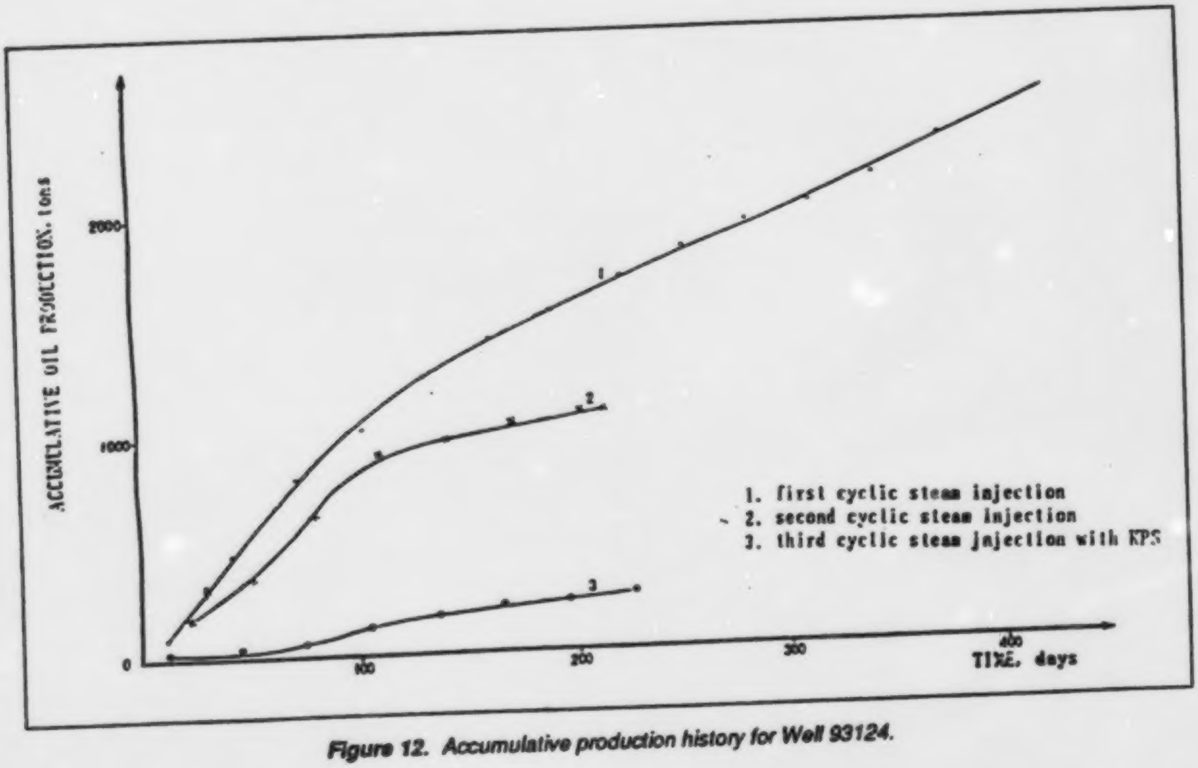

Figure 12. Accumulative production history for Well 93124.

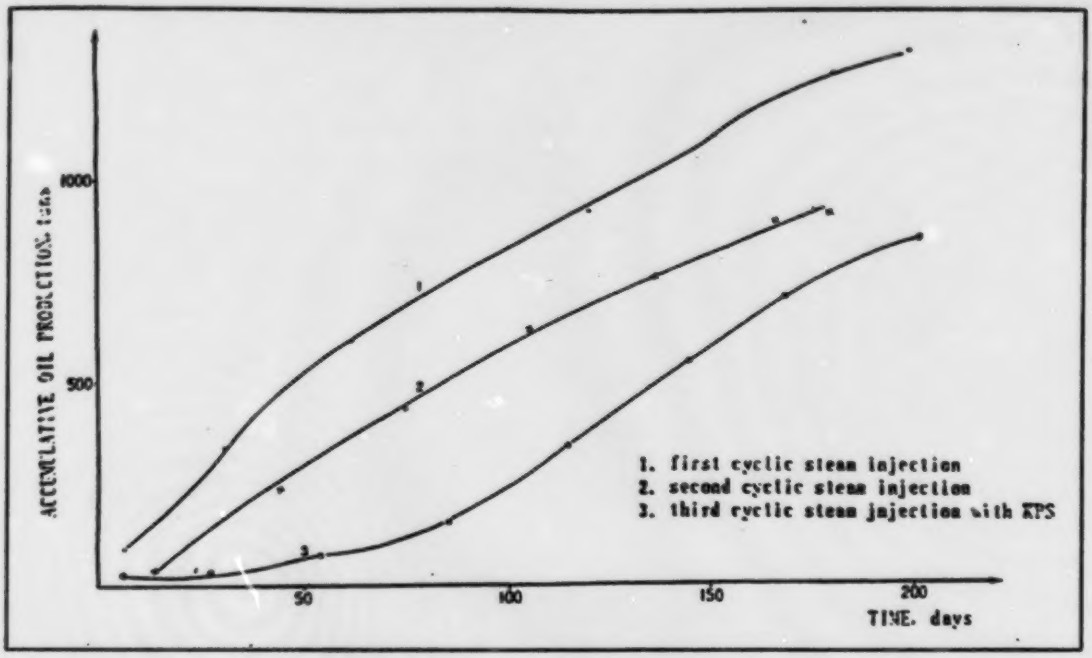

Figure 13. Accumulative production history for Well 93080.

4. The mechanical problems caused the failure of tests on two wells namely well 93246 and well 93124. Poor steam quality with low wellhead temperature (150°C) was experienced on the former. But the latter had a low injection pressure of 1.8 MPa during the test compared to 6.4 MPa in the preceding cycle. Such low steam injection rates simply could not heat the reservoirs even with the help from KPS surfactants. In fact, the mechanical problems also influenced other testing wells and their productions. For example, well 93080 responded very well during the production cycle, but its pump failure deteriorated oil production for 36 days. The same obstacle was found in producer 93079. The other problems including low steam injection rate on well 9153, and nine days shut down for workover on well 93233, also affected oil production. If these difficulties could have been eliminated, the results of the mentioned field tests should have been much better.

CONCLUSIONS

1. KPS surfactants possess a good thermal stability, and are capable of reducing oil-water interfacial tension, changing rock wettability towards water wet, and forming oil-in-water emulsion. The viscosity of this emulsion is much lower than that of the heavy oil. Therefore, the KPS surfactants assist oil to improve its mobility during steam stimulation, and consequently enhances oil recovery.
2. The field tests confirmed that KPS surfactants were effective in increasing oil rates and recovery from steam stimulation wells. This is based on: the success ratio of the tested wells was 80%, the incremental oil per success well was 537 tonnes, and each tonne of KPS surfactants injection produced 126 tonnes of incremental oil.

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INTEGRATED RESERVOIR ANALYSIS, A CASE STUDY

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ABSTRACT

The successful exploitation of hydrocarbon reservoirs depends not only on suitable processes, but also on an accurate characterization of the reservoir. In order to develop techniques for quantitative reservoir characterization, the Provost Upper Mannville B Pool in the heavy oil belt of east central Alberta was used as a case study. The reservoir is contained in sands of Lower Cretaceous age and is up to 35 m thick. Original oil in place has been estimated at approximately 34,200,000 m^3 of 13°API oil. The reservoir contains local areas of underlying water. Wells in the reservoir have primary production and several EOR projects are, or have been, active in the pool.

The reservoir sands were deposited in fluvial environments filling a valley system that was being aggraded during a sea level rise. The valley fill sequence can be divided into several lithofacies, four of which make up the reservoir. The main part of the reservoir is formed by the blocky channel lithofacies, and is overlain by the transition zone and channel margin lithofacies. The shale clast lithofacies, composed of zones of shale breccia or shale clasts in a sand matrix, represents a heterogeneity within parts of the blocky channel and transition zone lithofacies. Shale clasts constitute as much as 70% by volume in some ones and represent a significant vertical barrier to fluid flow within the reservoir. The reservoir can be divided into five flow units: the water saturated blocky channel sands; the oil saturated blocky channel sands; the transition zone sands; the channel margin sands and the shale clast zones.

Petrophysical properties, such as absolute permeability, have been characterized for each of the flow units in the reservoir. The relatively "uniform" oil and water saturated sands, transition zone sands, and the channel margin sands were characterized using statistical and petrographic image analysis techniques. This has shown that pore systems can be correlated with lithofacies, flow units and permeability. Pore types and their characteristics, as defined by petrographic image analysis, can be used to qualitatively infer other petrophysical properties such as capillary pressure and residual saturation. The extremely heterogeneous shale clast zones were characterized using 2D numerical flow simulation on digitized core intervals, and scaling-up techniques to convert the core scale data to the reservoir grid block scale. The combination of these characterization techniques provides a quantitative characterization of the reservoir, suitable for process simulation studies.

INTRODUCTION

The oil sands and heavy oil deposits of Western Canada with resources of 471.6 x 10^9 m^3 bitumen (Outtrim and Evans, 1978; MacCallum and McCrossan, 1979; Wilson and Bennet, 1985) represent Canada's largest future energy resource. Only a small portion (about 5%) is recoverable by surface mining methods, the remainder must be recovered by in situ techniques. The oil sands and heavy oil reservoirs are heterogeneous and complex, and an integrated team with expertise in geology, petrophysics, reservoir engineering and numerical modelling is needed to develop processes specific to individual reservoirs for the recovery of these resources. These recovery processes need to be based on a detailed characterization of the reservoir. With this in mind, the Alberta Geological Survey, through its Joint Oil Sands Geology.

Program with the Alberta Oil Sands Technology and Research Authority (AOSTRA) and the Alberta Department of Energy, initiated a project with the objective to develop and evaluate techniques for the detailed characterization of oil sands and heavy oil reservoirs for use in numerical process simulations.

This paper reports on studies carried out in the Provost Upper Mannville B Pool. The sandy portions of this reservoir have been characterized from the pore scale to the reservoir flow unit scale, using a variety of techniques. Characterization of the heterogeneous portions in the reservoir was carried out using numerical modelling of fluid flow through two dimensional domains based on images of actual core-size regions, and then scaling these results up to the grid block scale. The combination of these approaches in one project has provided a comprehensive quantitative characterization of the reservoir flow units, suitable for process simulation studies.

The Provost Upper Mannville B Pool was chosen for study because of the pool's limited stratigraphic and areal extent; the variety of reservoir conditions (such as bottom water, gas cap and permeability barriers); good data control (logs and core); and because several EOR projects are, or have been, active in the pool. In addition, data on its reservoir properties, useful for numerical process simulation, are available in the public domain through a series of Petroleum Recovery Institute reports (Collins, 1977; Collins and Pilles, 1981; Hayashitani and Davis, 1981), and a paper by Nazarko (1983).

STUDY AREA

The Provost Upper Mannville B Pool is located in east central Alberta, Canada (Figure 1), in McLaren Formation channel sands of Lower Cretaceous (Albian) age (Figure 2), at a depth of approximately 725 m KB. The reservoir is long and narrow, approximately 1.5 km wide by 15 km long, and up to 35 m thick, with an average net pay of 10–12 m. It is underlain by shales and silts of the Waseca Formation and capped by McLaren Formation shales and the overlying Colony Formation.

The Alberta Energy Resources Conservation Board has estimated original oil in place at 34,200,000 m^3 of 13°API oil. Primary production is in the 5 percent range OOIP, with initial production up to 10 m^3/day/well with a low water cut. Several EOR projects are or have been active in the pool. Nazarko (1983) mentions two single well steam projects and describes a combustion pilot composed of seven, 6-hectare seven spots. Currently, a steam pilot is being operated by Norcen Energy Resources Ltd. in Sec. 20, Twp. 37, Rge. 1W4. (Salahub and Mudie, 1990).

RESERVOIR GEOLOGY

Regional Setting

The mixed marine and continental sand/shale sequence of the Lower Cretaceous Mannville Group (Figure 2) unconformably overlies Paleozoic carbonate rocks and in turn is unconformably overlain by the marine Joli Fou shales of the Colorado Group. The McLaren Formation along with the overlying Colony and underlying Waseca Formations make up the Upper Mannville Group. The regional setting of the Mannville Group in Alberta has been discussed by numerous authors. The most recent detailed treatment is provided by Jackson (1984), in a series of paleogeographic maps covering selected time intervals through the Mannville Group. Other authors who have considered the Mannville sediments in the heavy oil region include Orr et al. (1977) and Vigrass (1977). Studies which focus on the McLaren Formation include papers by Gross (1980, 1981a, 1981b) on the Provost Upper Mannville B Pool; and Richardson and Vigrass (1984) and Vigrass et al (1987) on the Neilburg McLaren pool in Saskatchewan.

A number of depositional cycles are recognized within the Mannville Group in central Alberta and western Saskatchewan. Sheet sands, consisting of one or more coarsening upward shale to sand sequences can be correlated over large areas using a combination of geophysical well logs and cores. A number of thick, linear trending sand bodies, generally considered to be of channel origin by most authors, cut through these regional sand cycles. In the Provost area, the regional McLaren is cut by one of these channels and thick fluvial sands form the reservoir for the Provost Upper Mannville B Pool.

LITHOFACIES

The McLaren Formation in the Provost area can be subdivided into a regional McLaren and a McLaren

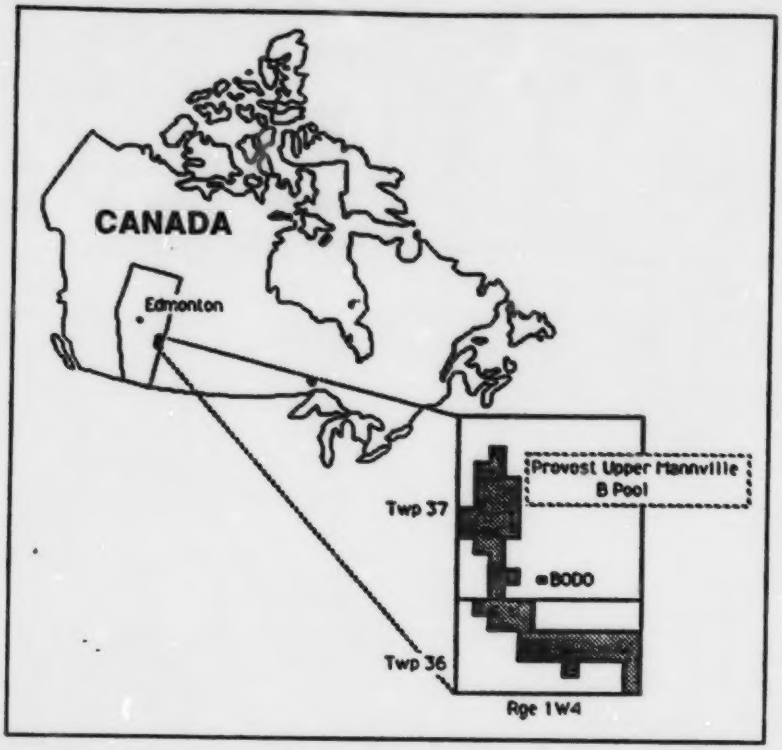
CANADA
Edmonton
Provost Upper Mannville B Pool
Twp 37
BODO
Twp 36
Rge 1W4

Figure 1. Index map showing the location of the Provost Upper Mannville B Pool.

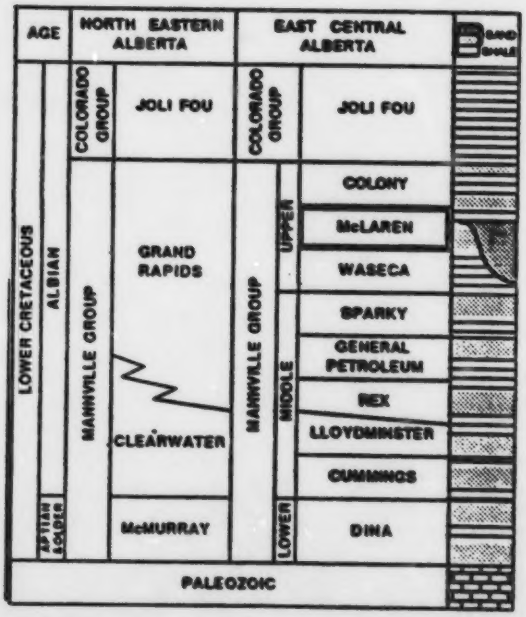
AGE
NORTH EASTERN ALBERTA
EAST CENTRAL ALBERTA
SAND
SHALE
LOWER CRETACEOUS
ALBIAN
APTIAN
COLORADO GROUP
JOLI FOU
COLORADO GROUP
JOLI FOU
MANNVILLE GROUP
GRAND RAPIDS
CLEARWATER
McMURRAY
MANNVILLE GROUP
UPPER
MIDDLE
LOWER
COLONY
McLAREN
WASECA
SPARKY
GENERAL PETROLEUM
REX
LLOYDMINSTER
CUMMINGS
DINA
PALEOZOIC

Figure 2. Lower Cretaceous stratigraphy in northeastern and east central Alberta.

valley fill sequence. Figure 3 is an isopach of the valley fill sequence and shows the location of the McLaren valley. Figure 4 is a west to east stratigraphic cross section showing the external geometry of the valley fill, which can be subdivided into six distinct lithofacies representing different depositional environments. These lithofacies are recognizable on geophysical well logs and in cores. Figure 5 shows the Gamma Ray and Resistivity logs for a typical well, with lithology and oil saturation for five of the six lithofacies. Since the Provost Upper Mannville B pool is contained within the sediments of the valley fill sequence, only that sequence will be considered further.

Blocky Channel Lithofacies

The blocky channel lithofacies forms the main part of the reservoir. It consists of trough and planar cross bedded, well sorted, quartz rich sands. Grain size varies from medium grained at the base to fine to medium grained near the top. The sands cut into the underlying Waseca Formation and occasionally Waseca fragments are found at the base of the sands. This is the thickest of all lithofacies, up to 20–25 m, and is interpreted as having been deposited in the main part of the channel complex that occupied the McLaren valley.

Transition Zone Lithofacies

This lithofacies overlies and is transitional with the underlying blocky channel lithofacies and grades upward into the overlying channel margin lithofacies. It represents the fining upward from the blocky channel sands to the finer grained channel margin sands. Grain size ranges from fine to medium grained to very fine grained at the top. Sedimentary structures vary from cross bedding at the base to laminations, ripple laminations, ripples and climbing

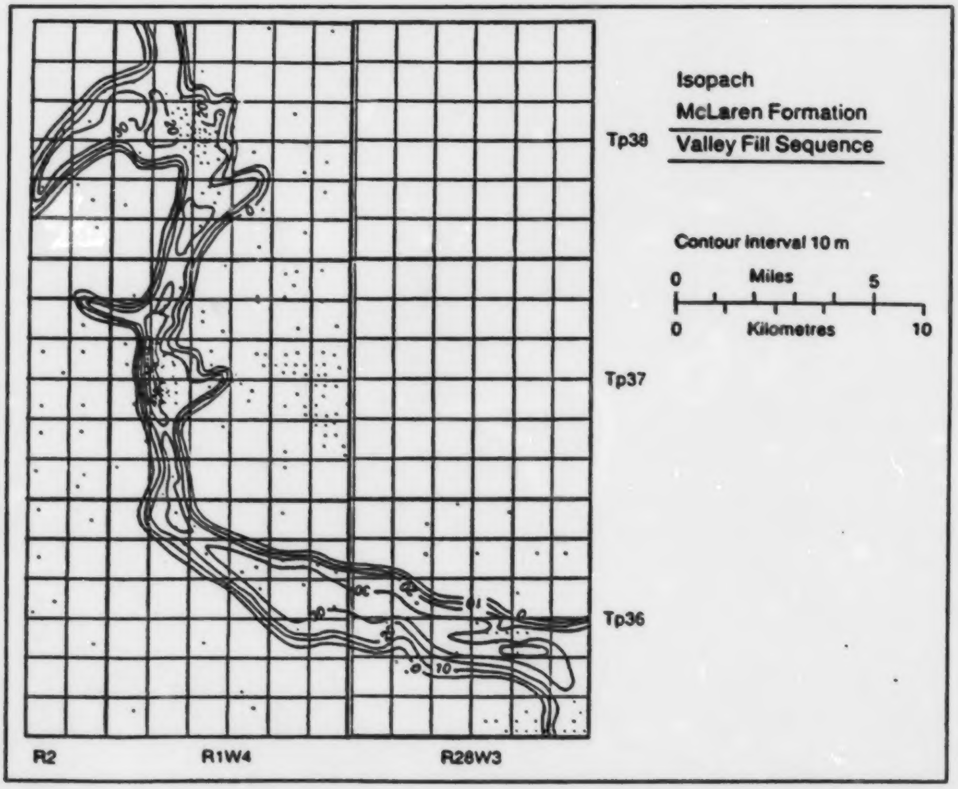

Figure 3. Isopach of McLaren Foramtion valley fill sequence.

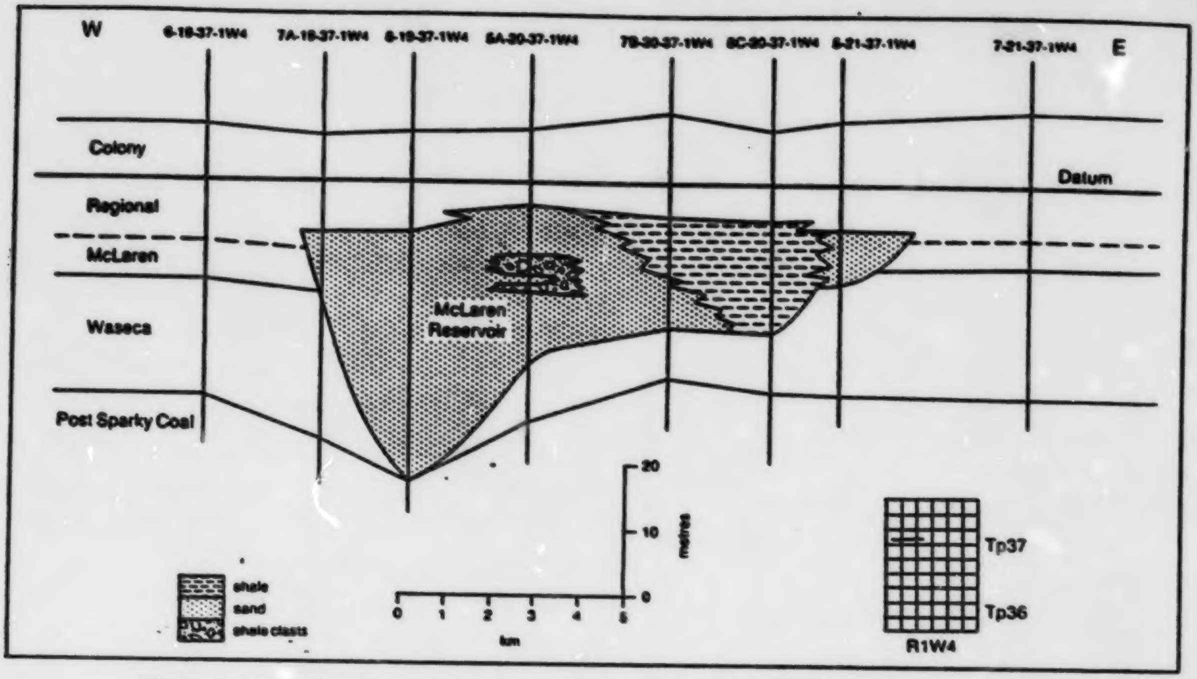
W
6-19-37-1W4
7A-19-37-1W4
8-19-37-1W4
5A-20-37-1W4
7B-20-37-1W4
8C-20-37-1W4
5-21-37-1W4
7-21-37-1W4
E
Colony
Datum
Regional
McLaren
Waseca
McLaren Reservoir
Post Sparky Coal
20
10
0
metres
0
1
2
3
4
5
km
shale
sand
shale clasts
Tp37
Tp36
R1W4

Figure 4. West to east stratigraphic cross section through the Provost Upper Mannville B Pool.

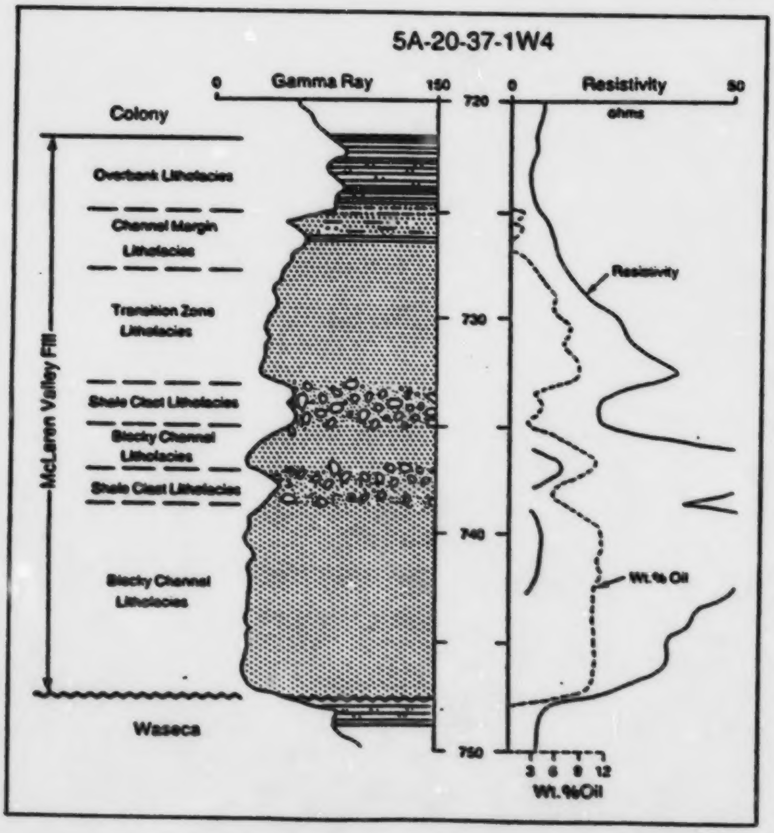

Figure 5. Typical well log from the Provost Upper Mannville B Pool showing four of the five lithofacies of the McLaren valley fill sequence.

ripples near the top. The thickness is highly variable, but can be up to 5 m.

Channel Margin Lithofacies

The channel margin lithofacies is the uppermost sandy facies. Grain size varies from fine- to very fine grained at the base to silty at the top. At the transitional base the sand is relatively clean, but quickly becomes argillaceous and has interbedded shale and silty shale beds near the top. Thickness varies from one to five metres. Deposition of this facies is interpreted as having occurred in the margins of the channel complex, on the edge of and on top of point bars.

Shale Clast Lithofacies

The shale clast lithofacies is found within the blocky channel and transition zone lithofacies and could be considered a subfacies. It consists of shale, silty shale or carbonaceous siltstone clasts in a matrix of fine to medium grained heavy oil sands. The clasts vary in size from several millimetres to decimetres. Clast shapes vary from equant to flat and from well rounded to very angular. In two dimensional cross sections, the clasts are on average twice as long as they are thick and have a subhorizontal orientation. Some of the clasts are structureless, whereas others show laminations or soft sediment deformation structures. Density of the clasts varies from an occasional clast to as high as 70% in core cross section.

Gross thickness of the shale clast lithofacies is up to 14 m, with the thickest continuous zone being 3 m. Lateral continuity of intervals with shale clast zones is expected to be on the order of tens to hundreds of metres. In the steam pilot in Twp. 37, Rge. 1W4 (Figure 1), shale clast zone intervals can be correlated across the pilot in an east to west direction, a distance of approximately 400 m. In the north to south direction, the same interval can only be correlated between two wells 25 m apart, and not between the wells which are 400 m apart. Figure 6 shows the areas within the reservoir where shale clast zones have been identified from cores and geophysical well logs.

The shale clast lithofacies is interpreted to have been deposited in the main part of the channel complex with the clasts coming from erosion of the channel cutbank. Shale clast zones are not unique to the Provost Upper Mannville B Pool. They have been observed elsewhere in the McLaren Formation, as well as in other reservoirs such as the McMurray Formation in the Athabasca Oil Sands, and can occur in any reservoir of channel origin.

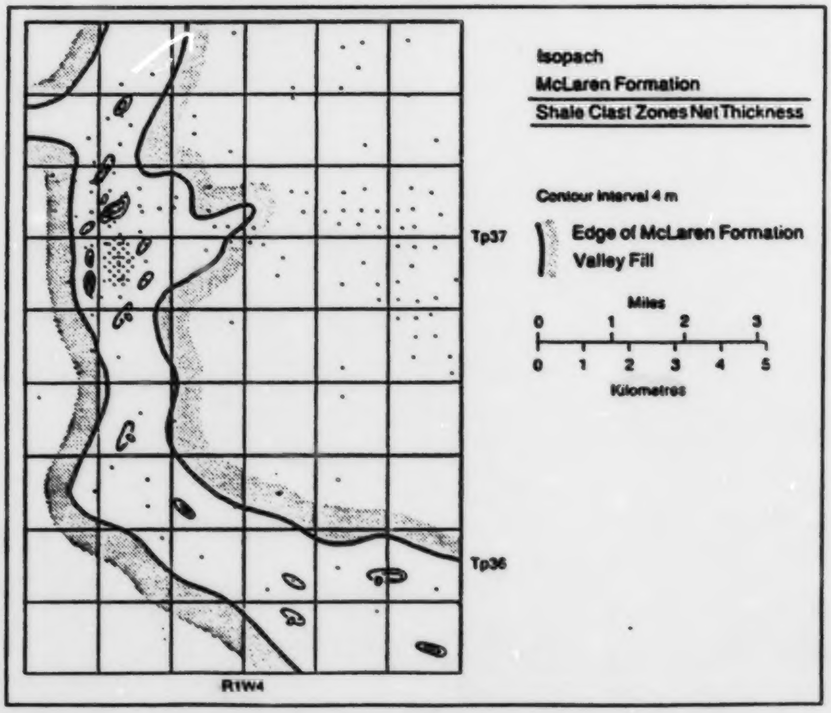

Figure 6. Isopach of the gross thickness of the shale clast zones.

Overbank Lithofacies

Forming the seal on the reservoir and transitionally overlying the channel margin lithofacies are a series of green to greenish gray shales and silty shales of the overbank lithofacies. Some interspersed silty laminae or thin silty beds can occur near the base. Carbonaceous debris is found scattered throughout the shale and occasionally in laminae. Contorted bedding or soft sediment deformation structures are also present. Rootlets occur near the top of this facies. Waxy mudstones with slickensides are present near the top of this lithofacies in several cores, these may represent a soil horizon. The overbank facies, which varies in thickness from 3 to 23.7 m, is interpreted as having been deposited in the overbank areas of the channel complex.

Abandonment Lithofacies

The abandonment lithofacies is recognized in both cores and logs. It is a structureless shale to silty shale sequence with thin interbedded silt or sand laminations. Rootlets and burrows are commonly present. This lithofacies may overlie a thin interval of cross bedded sands from the blocky channel lithofacies.

DEPOSITIONAL ENVIRONMENTS

The development of the sequence stratigraphy concept (Wilgus, et al., 1988, van Wagoner, 1990) has shown that sea level fluctuations have been the norm through geologic time, rather than the exception. This relative lowering and rising of sea level helps to explain the depositional history of the reservoir sediments. After the regional McLaren Formation sediments were deposited in shallow marine and nearshore conditions, there was a lowering of base level, or relative sea level, resulting in the cutting of a valley system. The extent of this valley is shown in Figure 3. As base level rose, due to a rise in relative sea level, this valley was aggraded and the valley fill sediments were deposited.

The sequence of sedimentary structures (cross bedding → laminations → cross laminations → ripples) and sediment types (medium grained sand → very fine grained sand → silt and shale) found in most cores indicates a fluvial origin for the valley fill sediments. The interpretation of the depositional environment for the McLaren Formation valley fill sediments is that of a sandy, low sinuosity, fluvial system. In this type of system, shale clast zones can develop anywhere in the channel complex, with the class coming from erosion of the cutbank. The sandy nature of the system also explains why there is a lack of shale beds within the channel sands. A modern example of similar depositional conditions is found in the sandy braided river deposits of the South Saskatchewan River in central Saskatchewan (Cant and Walker, 1978). North of the Provost area there is evidence indicating that the sands represent amalgamated sets of channel deposits, as found by Wightman et al. (1987) in other areas of east central Alberta.

THE RESERVOIR

The Provost Upper Mannville B reservoir is contained entirely within the blocky channel, transition zone, shale clast and channel margin lithofacies of the McLaren valley fill sequence. Figure 7 is an isopach of these four lithofacies and is equivalent to the gross reservoir thickness. From this figure it can be seen that the maximum reservoir thickness of 35 m occurs in sections 17 to 20 in Twp. 37, Rge. 1W4. Figure 8 shows the net oil pay. Maximum net pay varies from 13 m in the southern portion of the pool to 26.5 m in the northern portion of the pool. Where underlying water occurs there is usually a transition to the water zone, varying from 1.5–4 m. Small gas pockets occur in structurally high areas.

Characterizing reservoir properties for process simulations involves scaling-up from core and well log derived values to the flow unit or reservoir grid block scale. On the basis of lithology and internal heterogeneity, the Provost Upper Mannville B Pool reservoir can be divided into two parts: the "relatively uniform" sandy portions; and the heterogeneous shale clast zones. Different techniques were used to characterize the reservoir properties for these two subdivisions, with an emphasis being placed on absolute permeability.

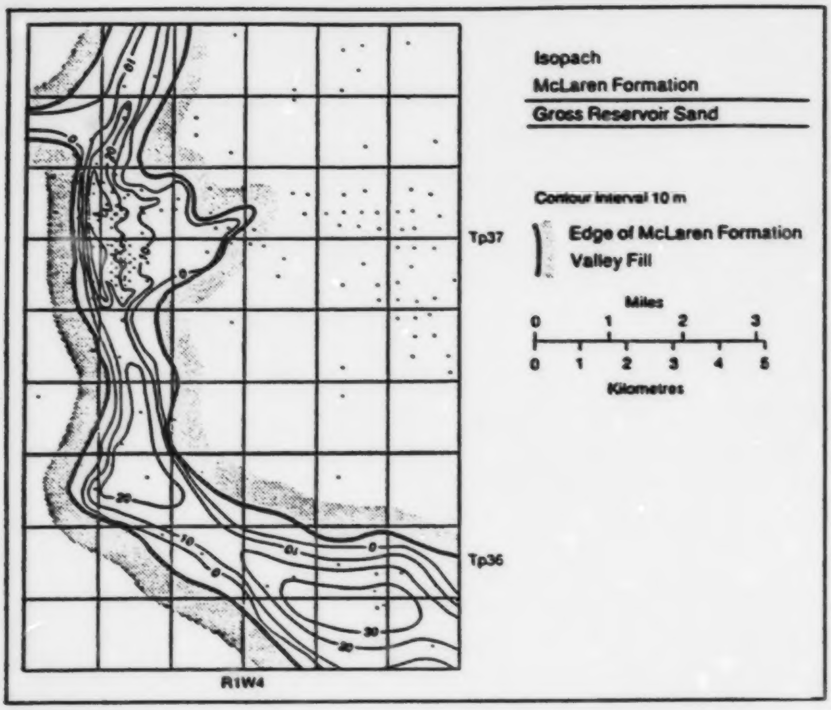
Isopach
McLaren Formation
Gross Reservoir Sand
Contour interval 10 m
Edge of McLaren Formation Valley Fill
Miles
0
1
2
3
0
1
2
3
4
5
Kilometres
Tp37
Tp36
R1W4
10
20
30
0

Figure 7. Isopach of the gross thickness of reservoir sands.

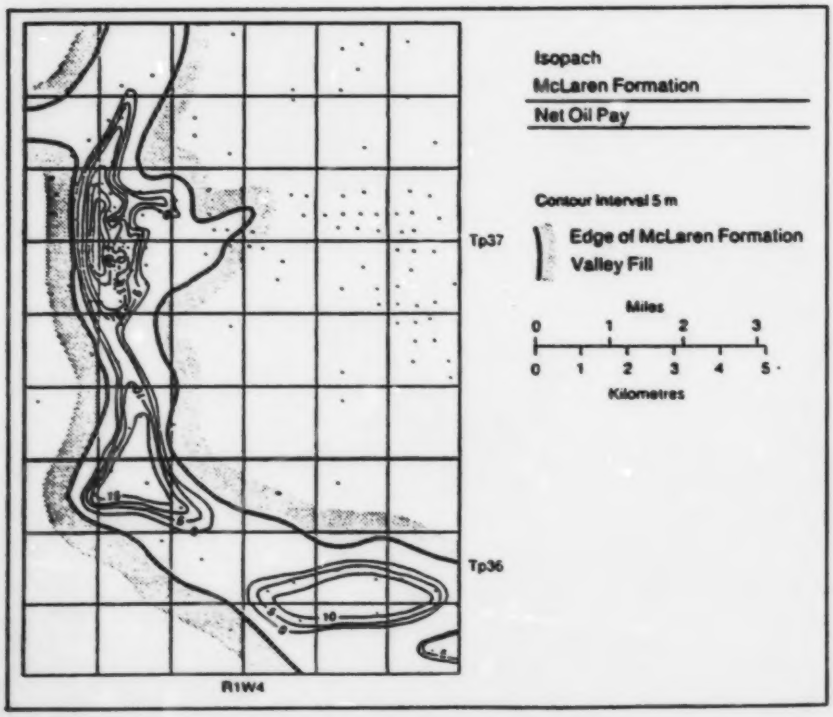
Isopach
McLaren Formation
Net Oil Pay
Contour interval 5 m
Edge of McLaren Formation Valley Fill
Miles
0
1
2
3
0
1
2
3
4
5
Kilometres
Tp37
Tp36
R1W4
10
5
0

Figure 8. Isopach of net oil pay.

SANDY FACIES CHARACTERIZATION

The sandy facies of the Provost Upper Mannville B Pool is comprised of the blocky channel transition zone and channel margin lithofacies. These three lithofacies represent a natural gradational sequence from the main channel complex, to the margins of the channel, to the point bar. In general, porosities in the blocky channel lithofacies average close to 30% with maximum oil saturation near 80%. In the transition and channel margin lithofacies, both porosity and oil saturation decrease upwards as a result of the fining upward trend in the reservoir lithology. Horizontal air permeabilities of 5 darcies (5×10^{-12} m^2) have been measured in fresh core samples from the blocky channel lithofacies. They decrease to the hundreds of millidarcies range near the top of the channel margin lithofacies. Because of this gradational nature, the sandy facies cannot be characterized by a single value in numerical simulations. Rather, it has to be divided into a number of layers that are based on the flow characteristics. A combination of techniques was used to characterize the absolute permeability of the Provost Upper Mannville B Pool sandy facies.

PORE SYSTEM ANALYSIS

Petrographic image analysis (Ehrlich, et al., 1984, Ehrlich and Davis, 1989, and Yuan, 1990) was used to characterize the pore systems of the sandy facies. Representative core plug samples were taken from each of the sandy lithofacies. Sixteen thin section images from each core plug were digitized as binary images representing pores and grains. An erosion-dilation image processing technique was then applied to each image to produce generalized pore size distributions. Measurements were averaged for each thin section. The size distributions for all the core plug samples were then analyzed by an unmixing algorithm (Full et al., 1981, 1984) to represent each sample as being composed of fractions of a number of end member pore systems. In order to evaluate pore connectedness, pore areas were divided into smooth and rough components. For each connected pore area, the smooth component is approximately the area of the largest inscribed circle and the rough component is the remaining pore area. A connectivity indicator was then defined as the ratio of the rough area to the total pore area. A value of zero corresponds to isolated circular pores and as the indicator approaches unity, the pore area typically consists of highly connected pores. Yuan (1990) discusses the methodology and theory of the petrographic image analysis technique, and the details of how it was applied to the Provost Upper Mannville B Pool sandy facies. Only the results of the petrographic image analysis are reported here.

A quantitative relationship between measured permeabilities and image data can be established by regression analysis. This can be used to predict permeability for those samples where no measurements are available. In this study, horizontal permeabilities were correlated to pore size and pore connectivity (Figure 9). The regression shows a high degree of correlation ($R^2 = 0.88$). The results from vertically oriented thin sections provide a better relationship than from horizontal thin sections. This is probably due to horizontal laminae in the core plug, which are better sampled by a vertical thin section.

The unmixing procedure (Full et al., 1981, 1984) used to identify the pore systems includes a Q-mode factor analysis with an iterative process to represent each sample as being composed of several end members. The number of end members is chosen in such a way that most of the variance of the size distributions are explained. Four end member pore systems were identified for the Provost Upper Mannville B Pool reservoir and the pore images in Figure 10 represent the closest real image examples of these four hypothetical end members. In general, end member one represents large highly connected pores; end member two represents medium size and highly connected pores; end member three is composed of medium-large but poorly connected pores; and end member four represents small and poorly connected pores.

The fractional end member amounts in each sample have been plotted within a tetrahedron (Figure 11) show the relationship between end member ore types and reservoir lithofacies. End member one is present in significant amounts in the oil saturated blocky channel sands, end member two

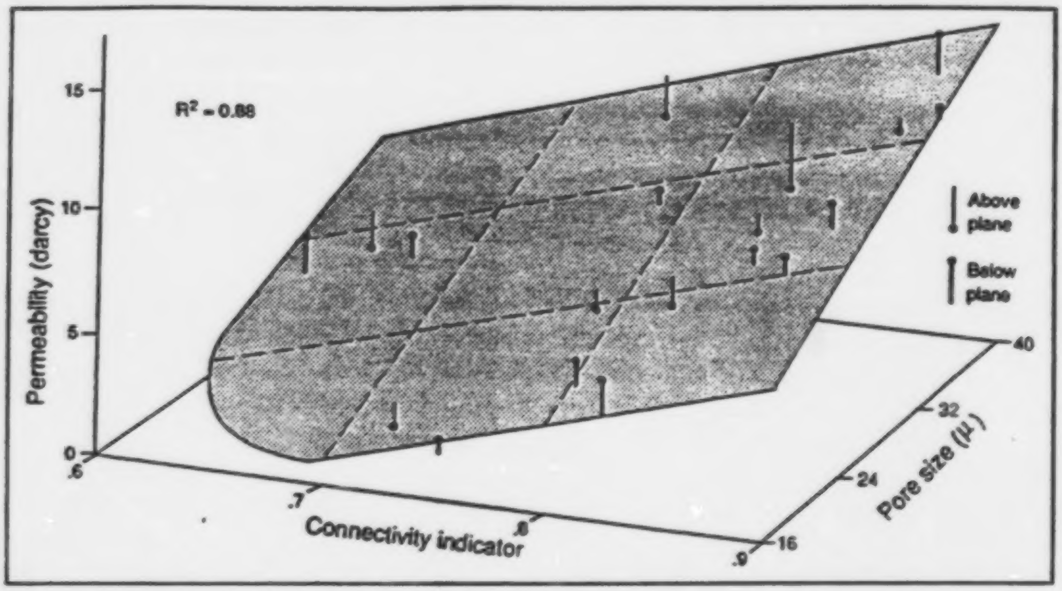

Figure 9. Regression relationship between pore size, connectivity indicator and permeability. The solid circles are the data projected on the regression surface and the vertical lines indicate the distance between the data point and their projection.

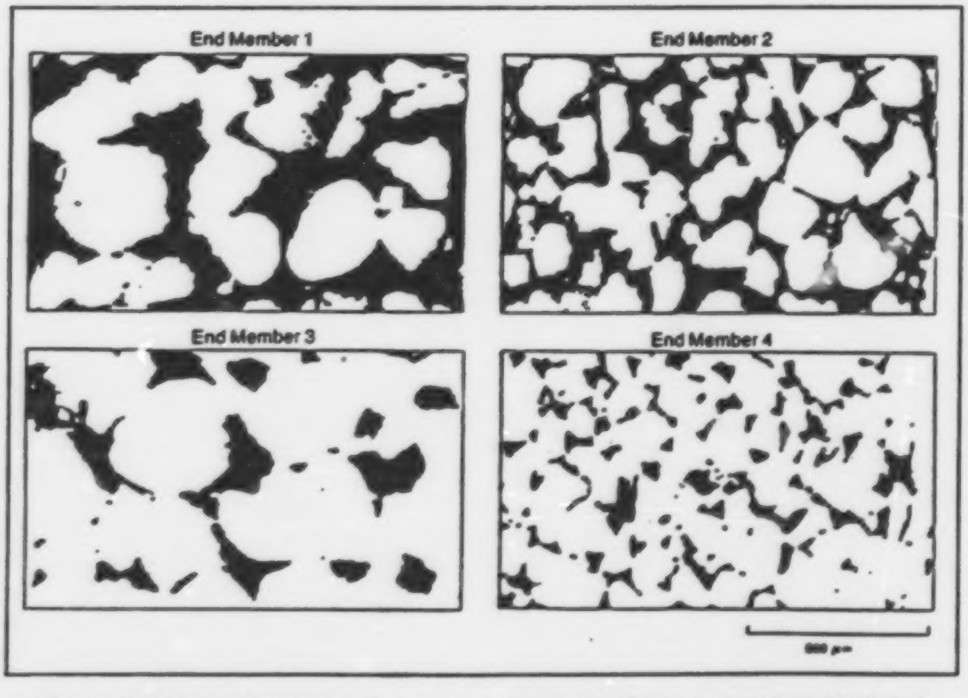
End Member 1
End Member 2
End Member 3
End Member 4

Figure 10. Characteristic pore system end members for the Provost Upper Mannville B Pool.

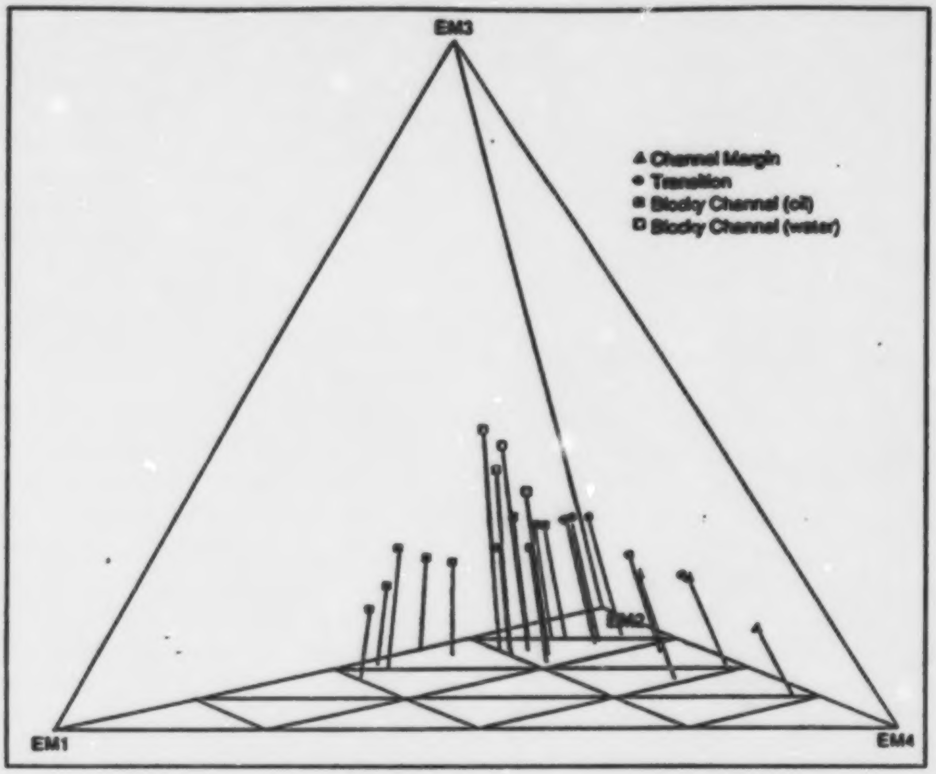

Figure 11. Plot of sample pore system end member composition and lithofacies.

is found in large amounts in the transition zone sands, end member three is closely associated with the water saturated blocky channel sands, and end member four is typical of the channel margin sands. The trend from end member one through end member two to end member four is closely related to the fining upward sequence found in the reservoir. The poorly connected pore networks found in end member three sands, typical of the water saturated blocky channel sands, is the result of a different diagenetic history of these sands compared to the other sands. After oil invaded the reservoir, formation fluids were still able to access those sands in the underlying water leg, thus allowing diagenetic processes to continue; whereas in the oil saturated portion of the reservoir diagenetic processes either came to a standstill or were severely inhibited.

Linking the reservoir pore systems and lithofacies has allowed for a qualitative extension of flow parameters to areas of the reservoir where only geological information is available. In addition, it also provides a methodology to predict absolute permeability values for samples where no measurements are available.

CAPILLARITY AND PORE SYSTEMS

In addition to predicting permeability values, other flow properties may be qualitatively estimated from pore characteristics. Capillary pressure and residual saturation depend to a large extent on the characteristics of the pore network. Thus a knowledge of the pore systems in a reservoir should result in a qualitative understanding of such properties as capillary pressure and residual saturation. Large, connected pores should have a lower capillary pressure than small, poorly connected pores. Sands with a highly connected pore network should have a lower non-wetting phase residual saturation than sands with a poorly connected pore network.

Drainage capillary: pressure-curves and residual non-wetting phase saturations (in this case air) were measured for three samples representing the oil and water saturated blocky channel sands and the transition zone sands. The results are shown in Figure 12. The horizontal part of the capillary curve, the "entry" pressure, is a measure of the critical throat size. As would be predicted from the pore characteristics, the sample with the largest connected pores (oil saturated blocky channel sand) has the lowest entry pressure, the largest critical throat size and highest permeability. The sample with the smaller, connected pores (transition zone sands) has the highest entry pressure, the smallest critical throat size and the lowest permeability. The water saturated blocky channel sand sample, which has medium sized, less connected pores, has values of entry pressure, critical throat size and permeability intermediate between those of the other two samples.

The vertical part of the capillary curve, irreducible water saturation, is a function of the grain surface area which the wetting phase (water) contacts. Grain surface area is highly related to clay content and grain size. The fining upward sequence in the reservoir, caused by a decrease in grain size and an increase in clay content, has resulted in an upwards increase in the surface area in the oil saturated sands. Thus the transition zone sand sample has a higher irreducible water saturation than the oil saturated blocky channel sand (Figure 12). Figure 12 also shows that the water saturated blocky channel sand sample has the highest irreducible water saturation. This is probably the result of a larger grain surface area caused by the presence of diagenetic clays in this part of the reservoir.

The results in Figure 12 show that the water saturated blocky channel sands, with the least connected pores, has the highest residual saturation. Of the two samples with the highly connected pore

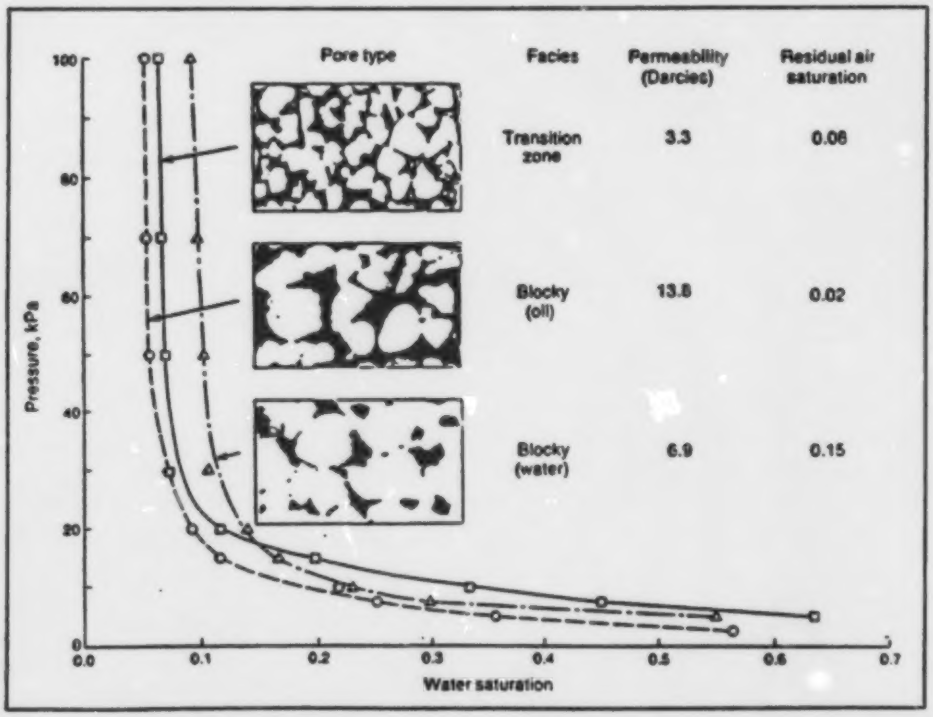

Figure 12. Capillary pressure and residual saturation curves for samples from the oil and water saturated blocky channel sands, and the transition zone sands.

networks, the oil saturated blocky channel sands, with the largest pores and pore throats, have the smaller residual non-wetting phase saturation. This agrees with Li and Wardlaw (1986) and Kirkpatrick (1973), that the residual non-wetting phase saturation is controlled by the connectedness of the pore networks, in addition to the sizes of pores and pore throats.

DEFINITION OF FLOW UNITS

Within the sandy facies of the Provost Upper Mannville B Pool there is a large body of petrophysical data measured from cores. This consists of interval measurements of fluid saturations and porosity, and discrete, point (plug) measurements of permeability. These data need to be scaled up from the core scale to flow unit or grid block scale to be useful in numerical reservoir models to simulate recovery processes.

Most wells show a definite permeability versus depth trend, in which permeability is relatively constant in the main portion of the reservoir, the blocky channel lithofacies, then decreases towards the top of the reservoir through the transition zone and channel margin lithofacies. This trend is most clearly shown by wells in the currently active steam pilot (Figure 13). Not shown in Figure 13, because these wells do not have a water leg, is a lower permeability in the water saturated blocky channel sands than in the overlying oil saturated blocky channel sands. This overall trend of decreasing permeability towards the upper portions of the reservoir and lower permeability in the water saturated sands is what one would expect, based on the geologic nature of the reservoir. The overall fining upward cycle inherited from the depositional environment is the controlling factor of permeability trends within the reservoir, except for the diagenetic overprint in the water saturated sands.

The scaling up of core analysis measurements in individual wells to a characteristic value for flow units or grid blocks on a reservoir scale requires a sequential process (Cushman, 1984). The first step is to scale the core analysis measurements to flow units on a well by well basis. These values can then be scaled up to flow units on a reservoir scale. Figure 14 presents the results of the first step: subdivision of the reservoir into flow units and quantification of permeability values for each flow unit for an individual well. Based on lithology, fluid saturations, porosity and permeability measurements, the reservoir at the central injector in the steam pilot has been divided into a number of flow units. For each of these flow units a characteristic k_h and k_v has been obtained by calculating the geometric averages of the reported core analysis values (Weber and van Geuns, 1989). From the base to the top of the reservoir these are:

- Oil saturated blocky channel sands flow unit, with an average k_h of 3.8 darcies and k_v of 3.6 darcies. This flow unit extends from the base of the reservoir to the top of the upper shale clast interval.
- Transition zone flow unit, which in this well can be subdivided into two subunits based on porosity trends and measured permeability values. The lower subunit has an average k_h of 2.5 darcies and one measured k_v value of 2.3 darcies. The upper subunit, which has an overall lower porosity, has an average k_h of 1.3 darcies and k_v of 0.3 darcies.
- Channel margin sands flow unit, which has a very low oil saturation and interbedded silt and shale beds, with an average k_h of 0.4 darcies. No k_v measurements were made, but based on the lithologic characteristics, k_v is expected to be very low.

In addition to the sandy facies flow units, the two shale clast intervals (Figure 14) also represent distinct flow units. Their characteristic permeability values will be discussed later. For the Provost Upper Mannville B Pool, one more sandy facies flow unit has to be defined, even though it is not present in this particular well. This is the water saturated blocky channel sand flow unit, and it is expected to have k_h and k_v values slightly lower than the oil saturated blocky channel sand flow unit.

For single well numerical simulation of recovery processes, this step is probably sufficient to assign characteristic permeability values to the simulator grid blocks. If a recovery process is to be simulated

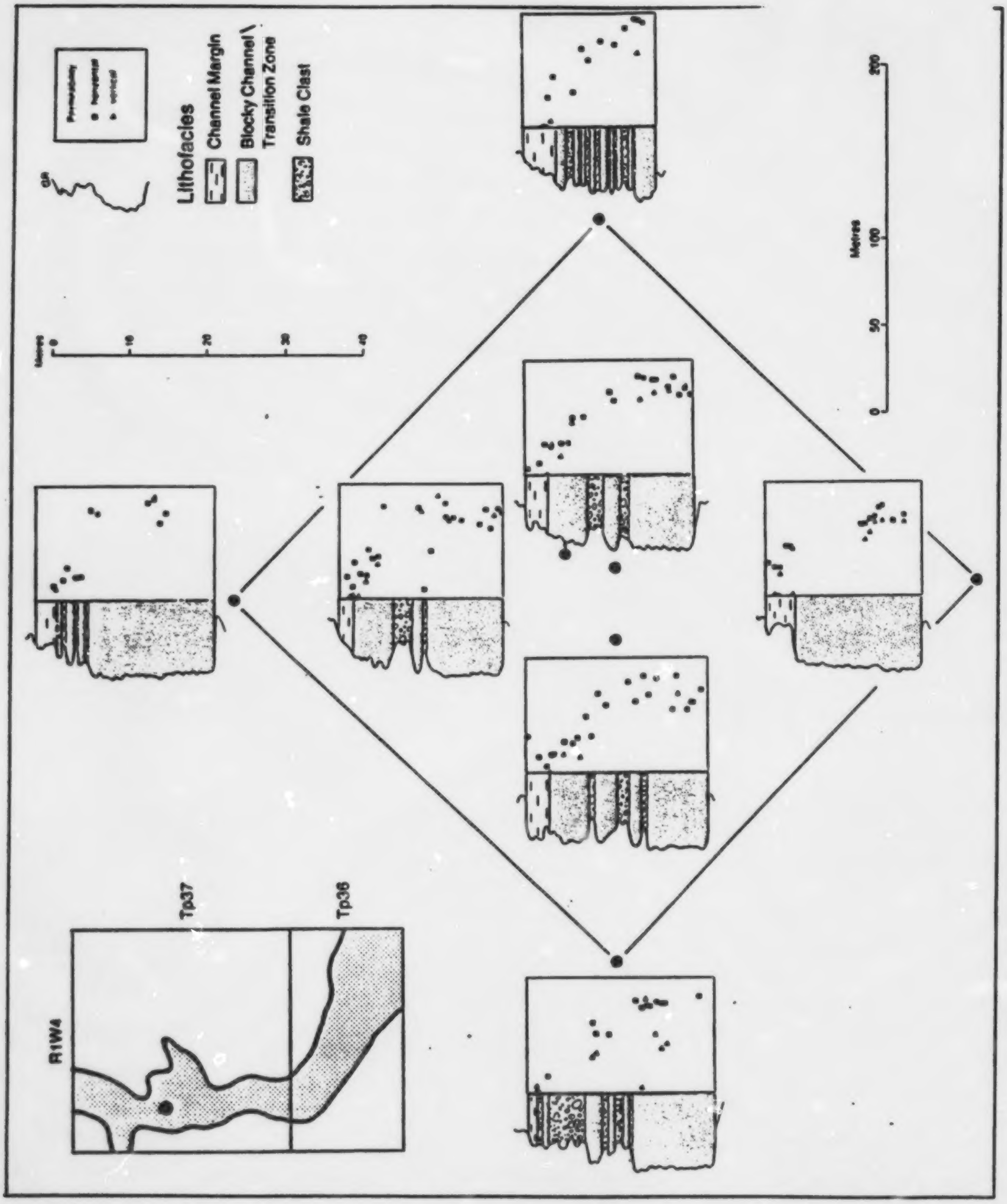
R1W4
Tp37
Tp36
Metres
0
10
20
30
40
GR
Lithofacies
Channel Margin
Blocky Channel \ Transition Zone
Shale Clast
Metres
0
50
100
200

Figure 13. Permeability trends for wells from the active steam pilot in the Provost Upper Mannville B Pool.

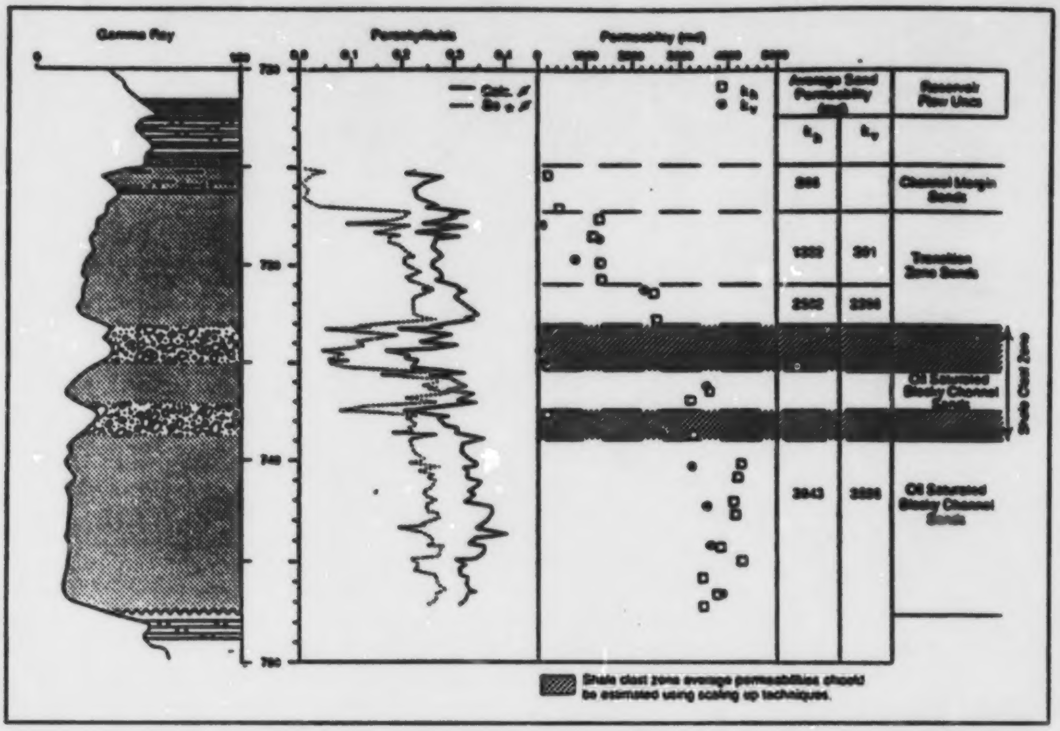

Figure 14. Sandy facies flow units and their characteristics permeability values for the central well in the steam pilot.

for a specific area of the reservoir, then this same process should be repeated for the other wells in order to obtain areal permeability trends for each of the flow units. These can then be used to assign characteristic permeability values to grid blocks used in the numerical simulator.

HETEROGENEOUS FACIES CHARACTERIZATION

The most heterogeneous facies of the Provost Upper Mannville B Pool are contained entirely within the shale clast lithofacies. Figure 15 shows a cored section through this lithofacies. The heterogeneity is provided by the contrast in properties between the individual shale breccia clasts and the embedding sand matrix. The permeability of these clasts is two to three orders of magnitude lower than that of the surrounding sands. Individual shale clast beds, or layers of amalgamated beds (Figure 16), cannot be correlated from well to well, even at a close well spacing. In Figure 16, the transition from bed to bed is marked by sudden changes in the size and shapes of the clasts, while within a bed these properties change very little. This is to be expected, as individual beds are created by different depositional events of cutbank erosion. Shale clast zones, consisting of interbedded sand beds and shale clast layers can be correlated at close well spacings. Figure 17 shows the interpreted outline of a shale clast zone correlated between four closely spaced wells. These shale clast zones are expected to present barriers to vertical fluid flow in the reservoir and thus have a potential impact on any recovery project.

The problem of determining an "effective" property for a heterogeneous region in a reservoir for the purpose of numerical process simulation has been a subject of great interest to reservoir engineers and hydrogeologists. A scaling up approach (Lasseter, et al., 1986) is commonly used and was adopted in this study to arrive at an effective permeability for a shale

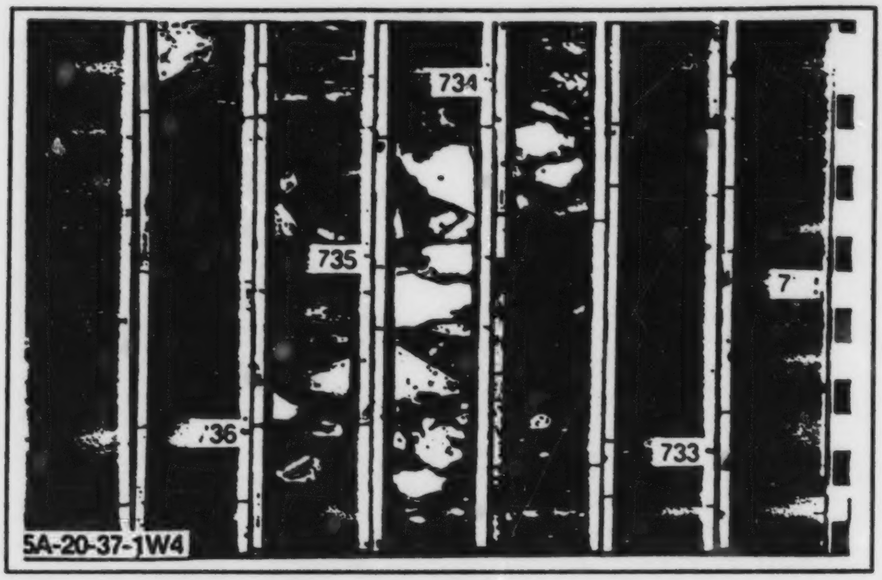

Figure 15. Cored section through the shale clast lithofacies in the 5A-20-37-1W4 well. The top of the core is in the upper right and each core tube is approximately 75 cm long.

clast zone. Cuthiell et al. (in press) discuss the detailed procedures of the scaling up process as applied to the heterogeneous shale clast zones. Briefly, a core scale region, several centimetres in size, contains a large enough sample of clasts to be representative at the smallest scale. Numerical fluid flow simulations performed on core scale regions produce effective values for horizontal and vertical permeabilities. To simulate the next scale up, a shale clast layer is represented by a large array of core scale blocks, each with its own effective properties. Thus, effective properties can be derived for the clast layer. In a similar manner, effective properties for a shale clast zone can be computed by simulating fluid flow through a shale clast zone composed of interbedded shale clast layers and sand layers, each with their individual effective properties.

CORE SCALE SIMULATIONS

Two dimensional fluid flow simulations were performed on sixteen core scale regions (Figure 18), ranging in clast fraction from 0.0268 to 0.497 and containing reasonably representative distributions of clasts. Horizontal flow was simulated by imposing a constant pressure differential between the sides of each interval and assuming impermeable boundaries at the top and bottom. Vertical flow was simulated in a similar manner. A shale clast/sand absolute permeability ratio of 0.001 was assumed to be realistic for this system.

The results of these simulations are graphically shown in Figure 19, as a plot of shale clast fraction versus equivalent permeability reduction, which is defined as effective permeability for the region divided by the sand phase permeability. Effective permeabilities decrease with increasing shale clast content, with the vertical permeability reduction reaching 0.129 at a shale clast fraction of 0.497. For any shale clast fraction, effective vertical permeability is smaller than horizontal. This core scale anisotropy is the result of the predominantly flat shape and sub-horizontal orientation of the clasts. A generalized weighted mean model (Korvin, 1982)

$$k_{eff} = \left[f k^{\omega} sh + (1-f)\, k^{\omega} ss\right]^{1/\omega}$$

was found to provide good fits to the effective permeability values, with $w_v = 0.243$ (vertical) and

w_h = 0.468 (horizontal), also shown in Figure 19. Both vertical and horizontal effective permeabilities lie between the arithmetic (w = 1) and geometric (w = 0) means. Neither of these standard averages provides a good prediction of effective permeability for the shale clast system at the core scale.

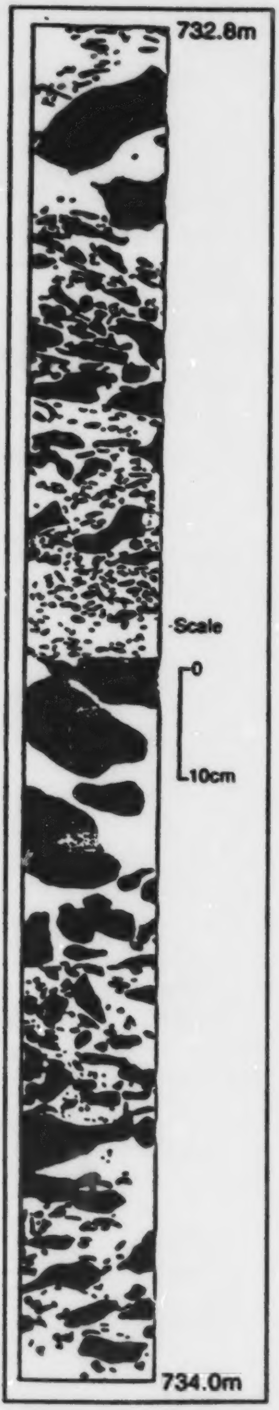

Figure 16. Digitized version of a typical shale clast layer.

SCALING UP FROM CORE TO ZONE SCALE

The scaling up from core to layer scale requires a knowledge of the variation in shale clast fraction within the layer. Core data provide a very small sample of this variability and therefore to estimate layer effective permeabilities based on core data requires several assumptions. For a particular layer in core, one may sample the clast distribution variations by dividing the layer into 20 cm intervals and computing a shale clast fraction for each interval. The resulting clast fractions can then be converted to effective horizontal and vertical permeabilities using the curves in Figure 19. Next, the assumption can be made that these core scale permeabilities are representative of the entire layer from which they were taken.

In order to estimate the effective permeabilities for the entire layer, it is also necessary to know the spatial distribution of the core scale effective permeabilities. Since this is normally not available, two extremes may be considered. One is that of horizontal stratification, in which shale fraction varies only vertically and not laterally within the layer. In this case the effective vertical and horizontal permeability would be given by the harmonic and arithmetic mean of the sampled core permeabilities, respectively. In the other, and less likely, extreme of vertical stratification, shale fraction would vary only laterally and not with depth in the layer. Effective vertical and horizontal permeability for the layer would be given by the arithmetic and harmonic means, respectively. For one actual layer, this reasoning leads to a range of possible values from 0.12 to 0.18 for vertical layer effective permeability reduction and from 0.31 to 0.35 for horizontal layer effective permeability reduction.

A practical method for estimating the layer effective permeability, based on results from numerical simulated layers, is to compute both

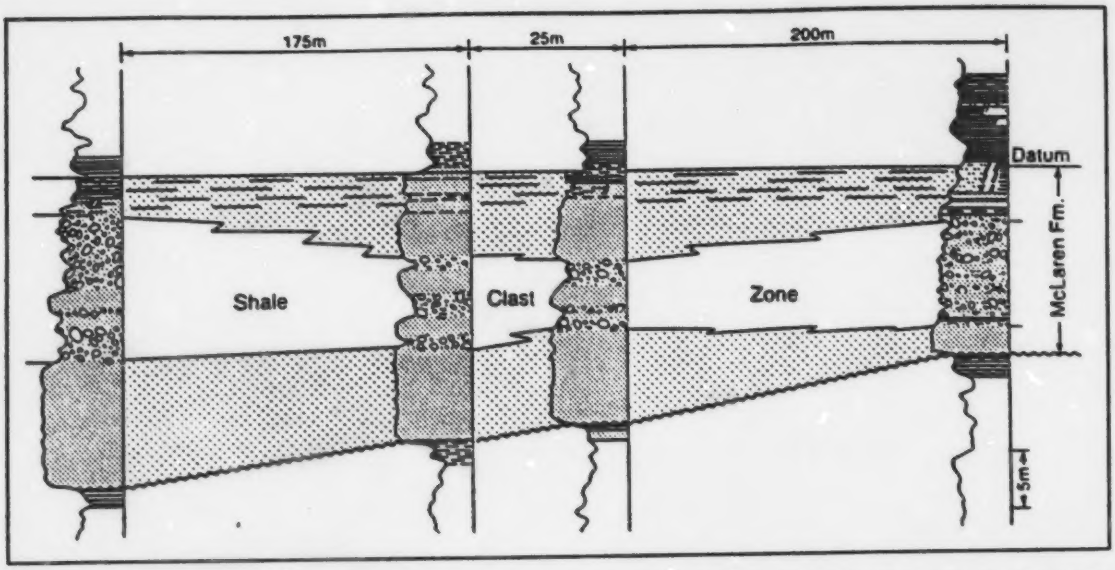
175m
25m
200m
Shale
Clast
Zone
Datum
McLaren Fm.
5m

Figure 17. Stratigraphic cross section through four closely spaced, cored wells showing the geometry of a shale clast zone.

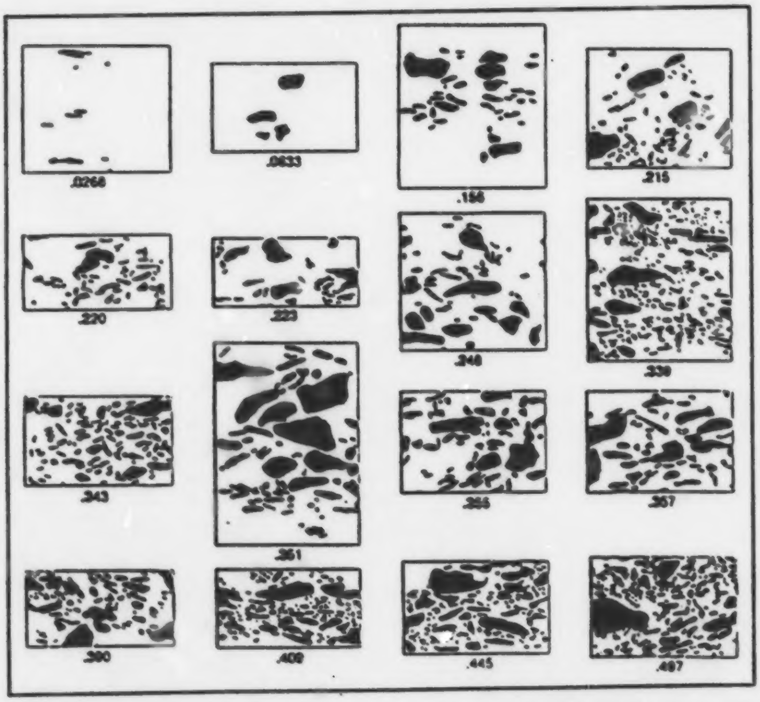
.0268
.0633
.156
.215
.220
.223
.246
.330
.343
.351
.355
.357
.390
.409
.445
.487

Figure 18. *Core scale images for which fluid flow simulations were performed. The shale clast fractions are indicated below each core scale interval.*

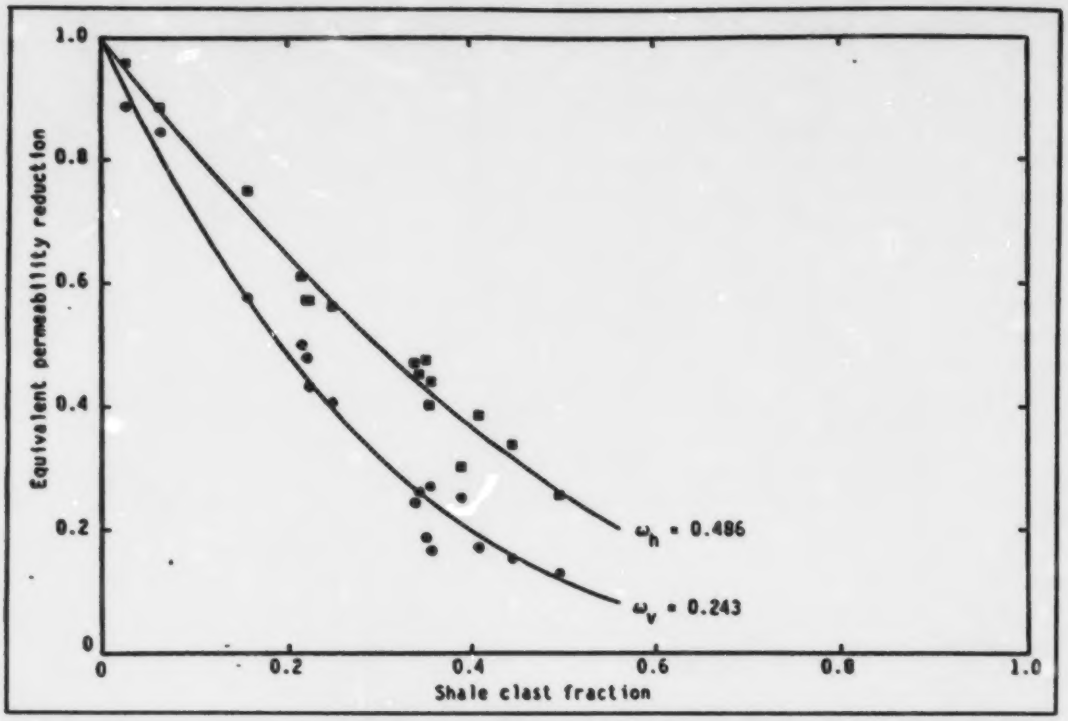

Figure 19. Results of core scale simulations and generalized weighted mean averages. The simulations assumed a shale clast/sand permeability ratio of 0.001.

vertical and horizontal layer effective permeability using the geometric means of the corresponding core scale values. For the example layer discussed above, this leads to values of 0.15 for vertical and 0.34 for horizontal effective permeability compared to the sand permeability.

At the zone scale, shale clast layers are analogous to the stochastic shales discussed by Haldorsen and Lake (1984). Thus, realistic distributions of layers within a shale clast zone can be created by the same method used by Haldorsen and Lake. Based on depositional conditions and geologic reasoning, the lateral dimension of a layer is expected to be much larger than the vertical dimension. Thus a shale clast zone is likely to be highly stratified. Therefore, the effective vertical permeability for a shale clast zone is expected to lie between the geometric and harmonic means of the layer values, and the effective horizontal permeability between the arithmetic and geometric means of the layer values. For the particular shale clast zone discussed above, the vertical permeability reduction is thus predicted to be between 0.23 and 0.31, and the horizontal permeability reduction between 0.52 and 0.59.

The core scale simulations and estimates of the layer and zone scale effective permeabilities are based on core derived two dimensional data. These results need to be extended to three dimensions in order to predict the actual reduction in permeability caused by shale clast zones and the effect that these zones will have on fluid flow in the reservoir. Physical flow experiments on a three dimensional shale clast analogue system and two dimensional numerical simulations on this system are currently underway and will be reported in the near future.

CONCLUSIONS

Using the Provost Upper Mannville B heavy oil pool in east central Alberta as a case study, a multidisciplinary approach to reservoir characterization has shown that:

1. The Lower Cretaceous McLaren Formation in the Provost area can be divided into a regional and a valley fill sequence, which in turn can be divided into six lithofacies. The Provost Upper Mannville B Pool reservoir is contained in the sediments of the blocky channel, transition zone, shale clast and channel margin lithofacies of the valley fill sequence. The reservoir sands were deposited in a sandy braided, low sinuosity fluvial system as the McLaren valley was aggraded during a rise in sea level.
2. Based on lithologic characteristics and internal heterogeneity, the reservoir can be divided into two main parts, a relatively "uniform" sandy portion, and a heterogeneous portion composed of shale clast breccia zones. Different characterization techniques need to be used for these dissimilar portions of the reservoir.
3. At the pore scale, the sandy portion of the reservoir was characterized using petrographic image analysis and four end member pore systems were identified. Pore system characteristics can be used to predict permeability values where no measurements were taken. Understanding the pore systems has also allowed for a qualitative assessment of capillarity and residual saturations.
4. At the reservoir scale, flow units were defined based on lithologic character, fluid saturations, porosity and permeability measurements. The sandy portion of the reservoir can be divided into four flow units: the water saturated blocky channel sands; the oil saturated blocky channel sands; the transition zone sands; and the channel margin sands. A characteristic horizontal and vertical permeability value was calculated for each flow unit. The shale clast zones represent a fifth flow unit.
5. A scaling up approach was used to arrive at effective permeability for the heterogeneous shale clast zones. This involved numerical fluid flow simulation at the core scale, and using computed standard averages for scaling up from the core to the layer and zone scale. For one particular shale clast zone, the effective horizontal permeability is predicted to be between 0.52 and 0.59 of the sand permeability, and the effective vertical permeability between 0.23 and 0.31 of the sand permeability. Thus these shale clast zones will act as barriers to fluid flow in the reservoir.

ACKNOWLEDGMENTS

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THE CHARACTERISTICS OF PRODUCED CRUDE FROM STEAM STIMULATION IN SHANJIASI OILFIELD

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ABSTRACT

The objective of this paper is to show the characteristics of produced oil from steam stimulation in Shanjiasi oil field.

During the steam stimulation tests in this field, the produced fluids from wells were systematically sampled on each cycle. The physical and chemical properties of the produced oil were analyzed. The results indicted that the light crude was produced earlier than the heavier crude.

INTRODUCTION

According tar sands (International Science Conference, 1982), the crude in this field with density of 0.9719 g/cm^3 (20°C) and viscosity of 6656 MPa·s (50°C) belongs to a typical heavy crude.

The analysis results of the samples from five wells in this field indicate:

- In the process of steaming the reservoir, the heavy crude appears to have a series of thermal physical and chemical reactions. These can be seen from the changes of the produced oil properties.
- In review of he oil property changes, the light crude came out before the heavier. This happened especially during the first month of production.

On a study of the mechanism of oil viscosity reduction under thermal stimulation, Venkatesan and Shu reported the variations of heavy oil properties at the testing temperature of 300°C.[1] In our study, we conducted a further investigation of this problem at the steam temperature between 300°C to 350°C in order to understand the effects of steam on high temperature cracking and distillation of heavy crude.

In addition, a study of the quality of the steam-making water, which might affect steam stimulation performance and oil recovery in the reservoir, was carried out for this project. The results indicate that $NaHCO_3$ type water would be decomposed in boilers at the high temperature. The product of such reaction, if it is injected into formation, might have some adverse effects on steam stimulation, since it creates water-heavy oil emulsification problems, which could increase the viscosity of the displaced fluids in the reservoir.

GEOLOGY AND TEST SITES

The productive zones in Shanjiasi oil field are in Ed and in Esi of the lower Tertiary age, and the depth at the center of formation is about 1200 meters. In general, the reservoirs are thick with good permeability and with relatively high porosity and water saturation. These in coupling with large heavy oil reserves provide the material foundation in this field.

Five wells located at Shan Block No. 10 east of the area, were selected for steam stimulation tests. Systematical sampling of fluids for analyses were carried out continuously on two wells for two cycles. In regarding the frequency of sampling, the early stage of operation was emphasized.

TEST FLOWCHARTS AND PROCEDURES

1. Sample analysis flowchart (Figure 1)
2. Cracking simulation test flowchart (Figure 2)
3. Emulsification simulation test flowchart (Figure 3)

Except these conventional analysis methods, the liquid chromatography analysis of aromatic hydrocarbon in crude will be discussed in this paper. (Instrument used SHIMADZU LC-4A; Column Zorbax-ODS)

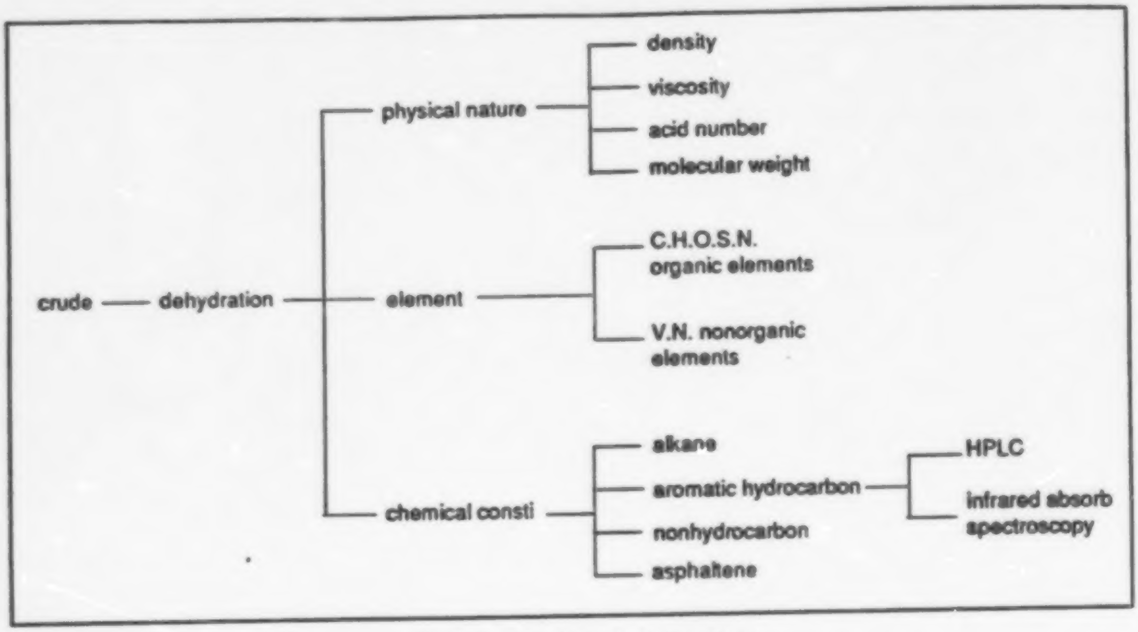
density
viscosity
physical nature
acid number
molecular weight
C.H.O.S.N.
organic elements
crude
dehydration
element
V.N. nonorganic
elements
alkane
HPLC
aromatic hydrocarbon
infrared absorb
spectroscopy
chemical consti
nonhydrocarbon
asphaltene

Figure 1. Sample analysis flowchart.

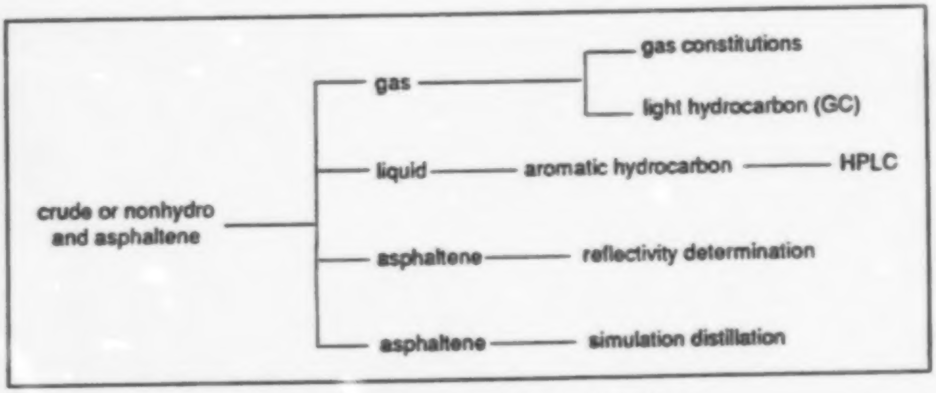
gas constitutions
gas
light hydrocarbon (GC)
liquid
aromatic hydrocarbon
HPLC
crude or nonhydro
and asphaltene
asphaltene
reflectivity determination
asphaltene
simulation distillation

Figure 2. Cracking simulation test flowchart.

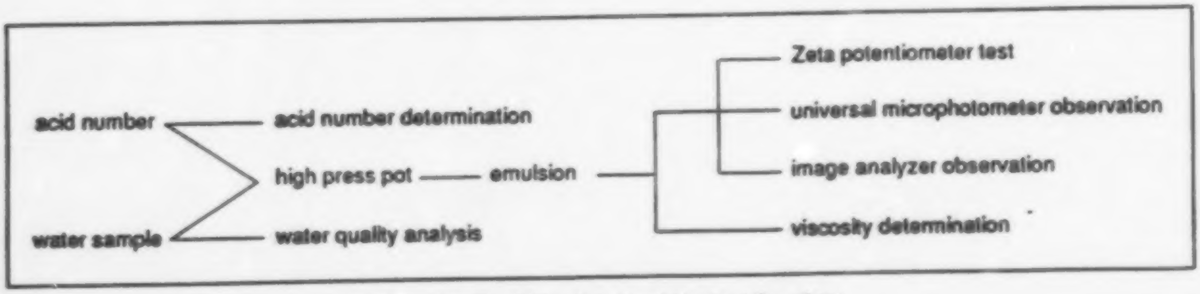
Zeta potentiometer test
acid number
acid number determination
universal microphotometer observation
high press pot
emulsion
image analyzer observation
water sample
water quality analysis
viscosity determination

Figure 3. Emulsification simulation test flowchart.

The principle index obtained from aromatic hydrocarbon analysis is the aromatic hydrocarbon "A" number, which reflects the amount of light aromatic hydrocarbons, such as Benzene and Naphthalene series in the sample. This number has certain relations with crude oil properties. The higher the "A" number it contains, the e light crude is. This analysis would not be affected by the amount of water in sample, but the results could indicate the type of oil produced from the steam stimulated wells.

RESULTS AND DISCUSSIONS

1. *The trend of changing produced oil properties from lighter to heavier during stimulation cycles.*

This change is especially significant in the first month when wells were put on production.

Data summarized from the analyses of physical and chemical properties of the produced oil are shown in Table 1, from which, the changes are:

oil density (g/cm^3)	0.9710	increased to 0.9805
oil viscosity mPa·s)	2911	increased to 10351
molecular weight	450	increased to 586

Table 2 lists the analyzed data for the aromatic hydrocarbon "A" numbers. Which decreased gradually from most from well 11-23, the said well had channeling steam problems during stimulation. In a review of the "A" data from well 11-15, the decrease in these measures reflects the change of oil-property from lighter to heavier during two-cycle operation

"A" number changes in second cycle (%)	22.7 to 15.42
"A" number changes in third cycle (%)	19.54 to 13.15

In addition, from the data plotted on Figures 1, 5, 6, and 7 and based on the results of elements analysis (H/C ratio) listed in Table 3, all of them support the previous statements that cycling steam stimulation changed oil-property in the produced crude, and this is especially true during the first month of the wells put on production.

In reviewing the results of aromatic infrared spectrum, the aromatic substitutions in oil are increasing cycle by cycle. This indicates the high temperature cracking resulted in dealkylating action in the crude.

Table 1. Physical property of crude and analyzed results of its chemical constituents

Well no.	Well open days	Crude physical property				Chemical constituent %				
		Density g/cm^3	Viscosity MPa·s	Molecular weight Mo	Acid number mgKOH/8	Alkane	Aromatic	Non hydrocarbon	Asphaltene	Total hydrocarbon
Shan Block 10 Well 25-9	11	0.9710	2911		6.25	36.60	23.33	23.30	7.67	59.93
	15	0.9734	9483		6.79	35.51	23.23	23.40	8.10	58.74
	29	0.9780	9858			33.78	22.36	23.08	8.03	56.14
	46	0.9785	9893			34.33	21.66	24.44	8.75	55.99
	77	0.9795	9966			33.00	21.24	25.97	8.47	55.24
	109	0.9795	9947			32.33	22.53	25.24	9.18	54.86
	149	0.9793	10173		6.49	31.86	20.78	25.45	9.49	52.64
	205	0.9805	10351		6.53	31.53	21.18	25.70	10.33	52.71
Shan Block 10 Well 11-15	6	0.9670			5.29	35.77	22.40	22.01	10.03	58.71
	6	0.9652	3376	450	5.71	36.10	20.06	21.67	7.36	56.16
	6	0.9666	3900		6.25	38.33	21.67	19.67	7.33	60.00
	10	0.9725	4771		6.41	35.29	21.67	22.29	8.47	56.96
	20	0.9713	6043		6.30	34.41	20.24	23.00	7.09	54.65
	35	0.9735	6161		6.18	34.69	20.71	23.93	8.96	55.40
	65	0.9762	6033			32.03	21.89	24.35	9.67	53.92
	96	0.9767	6164		6.07	31.57	21.31	23.67	8.69	52.88
	128	0.9724	6239		6.22	31.23	21.07	23.00	9.36	52.30
	168	0.9776	6409	586	6.06	31.18	20.00	24.33	9.33	51.13

Table 2. Analysis of aromatic hydrocarbon (HC)

Well	Prod. days	Aromatic HC "A" %	Aromatic HC "A" Variation %	Well	Prod. days	Aromatic HC "A" %	Aromatic HC "A" Variation %	Well	Prod. days	Aromatic HC "A" %	Aromatic HC "A" Variation %
11-15 2nd cycle				25-9 2nd cycle				23-11 2nd cycle			
Relative value		15.42		Relative value		11.39		Relative value		13.08	
11-15 3rd cycle				25-9 3rd cycle				23-11 3rd cycle			
Relative value		13.15		Relative value		113.14		Relative value		16.06	

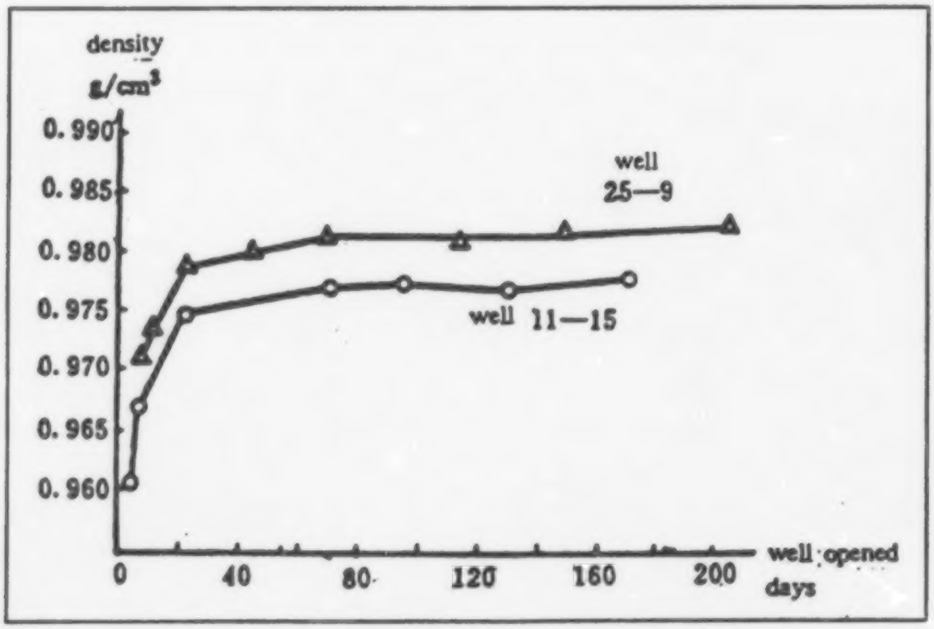

Figure 4. Density variation curves of crude.

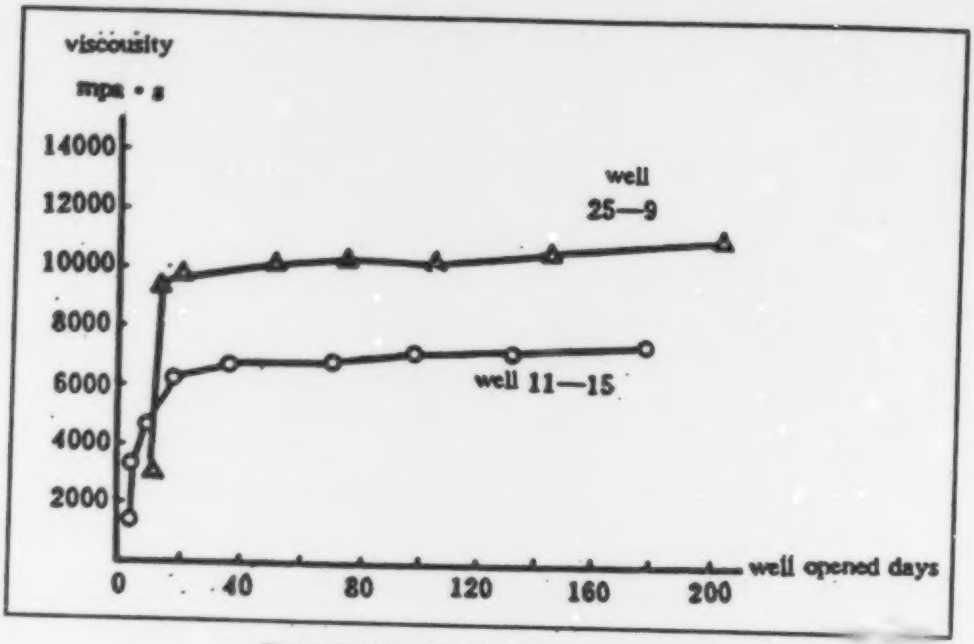

Figure 5. Viscosity variation curves for crude.

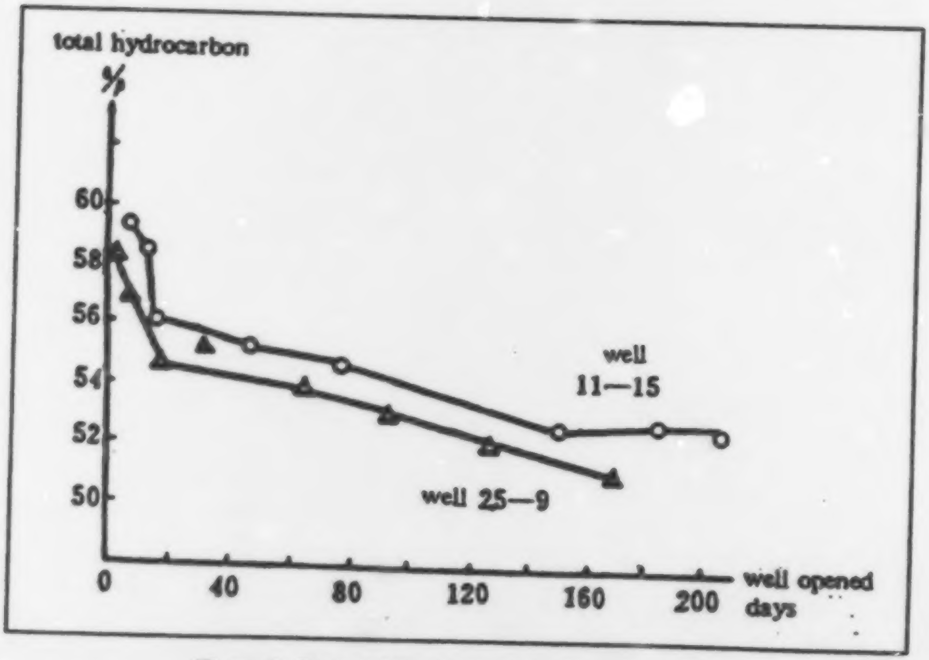

Figure 6. Total hydrocarbon variation curves for crude.

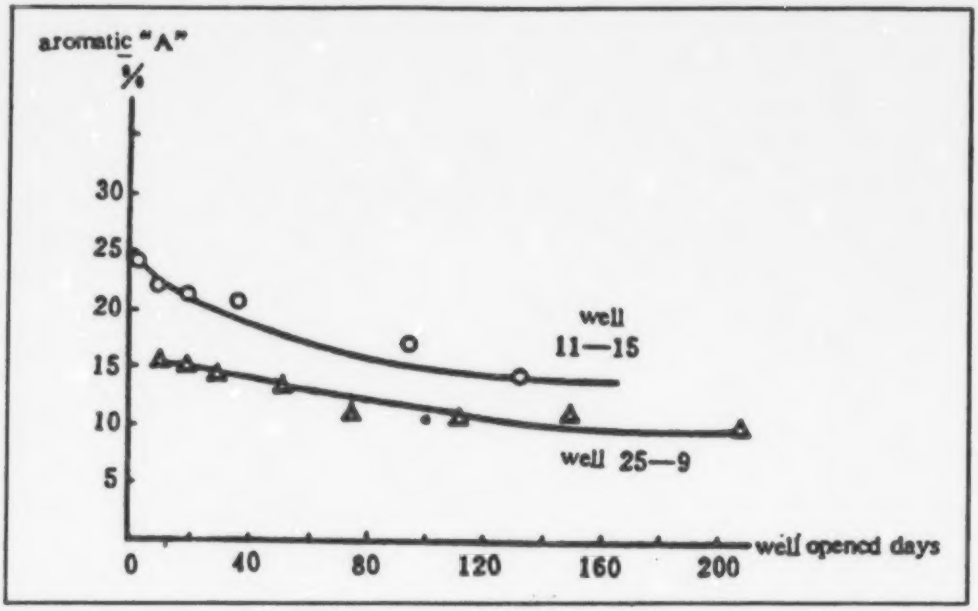

Figure 7. Aromatic "A" variation curves.

Table 3. Results of elements analysis

Well	Sample no.	Analysis, %								Mole ratio O/C × 10^{-3}
		C	H	O	S	N	V	Ni	H/C	
Shan Block 10 25-9										
Average										
Shan Block 10 11-15										
Average										

2. *Effects of steam stimulation on high temperature cracking and distillation.*

A thermal stimulation test for Shanjiasi crude was carried out in the laboratory. The sample was heated to 300°C for 24–120 hours at a condition without oxygen. During the test, only small amounts of gas were produced. However, with the increase of heating time, the color of the crude changed from brown and yellow light oil to a colorless condensate by thermal reaction. This shows that distillation existed in the test.

Similar tests were conducted on crude, nonhydrocarbon, and asphaltene at a slightly higher temperature (350°C and the vessel was either in vacuum or filled with helium. This time, much more gas was generated. The analyzed results of gas constitutions and the light hydrocarbon are presented in Tables 4 and 5

Table 4. Analysis of gases from high temperature cracking of crude and asphaltene

	Gas analysis												
Gas from	N_2	CO_2	CH_4	C_2H_4	C_2H_6	C_3H_6	C_3H_8	i-C_4	n-C_4	i-C_5	n-C_5	n-C_6	Air
crude													
asphaltene													

Table 5. Analysis of light hydrocarbons

No.	Compound	Weight %	No.	Compound	Weight %
1	Methane	34.81	11	3-Methylpentane	0.003
2	Ethane	30.51	12	n-Hexane	0.006
3	Propane	25.63	13	2,2-Dimethylpentane	0.001
4	i-Butane	5.89	14	Methylcyclopentane	0.0075
5	n-Butane	2.12	15	2,4-Dimethylpentane	0.001
6	i-Pentane	0.13	16	2,,2,3-Trimethylbutane	0.0
7	n-Pentane	0.08	17	Benzene	0.045
8	2,2-Dimethylbutane	0.01	18	Cyclohexane	0.01
9	Cyclopentane	0.229	19	2-Methylhexane	0.001
10	2-Methylpentane	0.018		Other hydrocarbons	0.005

respectively. The products shown in these two tables proved that high temperature cracking took place during the tests. In fact, thermal reaction played two different roles in changing the tested crude. Firstly, heat broke the ruptured chains or stripped lateral chains from large moleculars. And this created light hydrocarbon gases. On the other hand, the thermal reaction turned to form polycyclic aromatic hydrocarbon, asphaltene and carbon residues (Table 6). The reflectivity R_0 of asphaltene was tested by using microphotometers. The results indicated that R_0 rose gradually from 1.85 to 2.36 with the increase of heating time. This means carbonization was enhanced during the tests.

GC distillation test was carried out for the soluble products from the thermal stimulation study of nonhydrocarbon and asphaltene. When temperature was less than 300 °C, the fraction of the light component was about 7–9%. The light fractions inevitably raises productivity.

One of the thermal reaction product from crude is the coking constituent and carbon residues. Such materials with large moleculars usually stayed underground. As a result this might plug the formation and would change the rock wettability to oil wet. Consequently, it could reduce oil recovery. In the laboratory tests, this phenomenon was shown after the crude was

Table 6. Non-hydrocarbon and asphaltene cracking products

Sample no.	Testing temperature °C	Isotherm period hr.	Weight	Cracking products				
				Asphaltene		Solubles		Gas
				wt.	%	wt	%	%
Asphaltene-1		24	0.5249	0.5078	96.75	0.0160	3.05	0.2
Asphaltene-2	350	72	0.531	0.0443	83.48	0.0085	15.92	0.6
Asphaltene-3		144	0.5238	0.3906	73.31	0.1331	24.99	1.7
Non-hydrocarbon–1	350	72	0.5012	0.3280	65.45	0.1626	32.45	2.1

heated at 300°C for more than three days. However, even heated at 350°C for 24 hours, the significant increase of carbon residues was also indicated.

3. *Crude emulsification during steam stimulation.*

(a) Evident emulsification in steam stimulated wells. The Shanjiasi crude is number ranges from 5 to 8 (mg KOH/g). The type making water is $NaHCO_3$. Its pH value at the boiler entrance was 8.4–8.7, but it increased to 12 at the exits. The decomposition of $NaHCO_3$ in boiler at high temperature created CO_2, which was injected into formation because of the closed injection system. Since CO_2 could be dissolved in the oil, it would make water basic when it was produced. Thus, the reaction of oil with organic acids and the basic water resulted in certain products, these with fine interface activities would make oil and water emulsified.

By testing the oil samples in the field with Zeta potentiometer and imagine analyzer, the steamed Shanjiasi crude had evidence of emulsive feature. Which indicated the emulsion was water in oil (photos 1 and 2) and possess high viscosity that

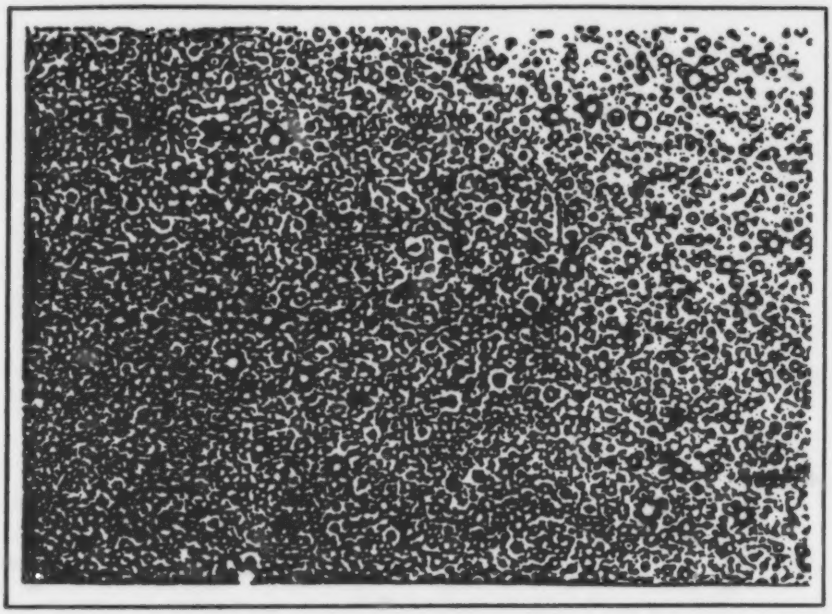

Photo 1. Water-in-oil emulsion (Well 11-15).

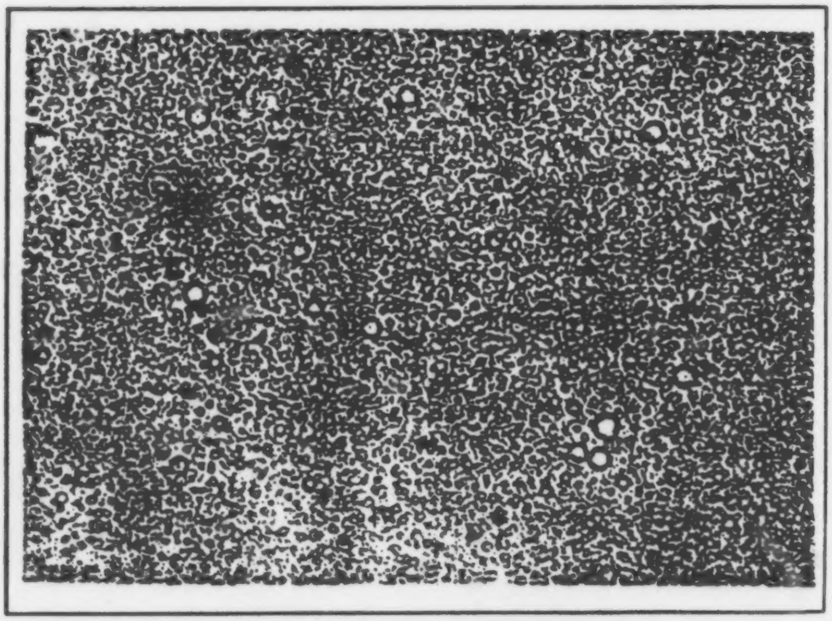

Photo 2. Water-in-oil emulsion (Well 25-17).

Notes: The above photos have been magnified 350 folds taken with UMSP-50 microscopic photometer.

is unfavourable for oil recovery by steam stimulation.

(b) Laboratory test of oil/water emulsification. The tests were conducted in a high pressured still with oil and water samples inside and agitated for twelve hours. From the results listed in Table 8, indicating whatever the water sample was taken, i.e., either from the boiler exit (pH 12.26 or from wellhead (8.41) would form emulsion with the Shanjiasi crude. The viscosity of the W/O emulsion increased 2.16–2.73 folds of the original value measured on oil.

Alkaline water injection actually is beneficial for oil displacement in EOR. In our case, however, it is necessary to develop thin-film extensioner (TFSA) for emulsion control, and a proper amount of additives should be added in the steam-making water to its pH value.

CONCLUSION AND SUGGESTIONS

1. During steam stimulation in Shanjiasi field, the properties of the produced oil varied considerably cycle by cycle. Lighter oil was produced before heavier, and this happened especially in the first month of production. When the lighter oil was gone, the rest in the reservoir became even viscose and heavier. This could affect the overall efficiency for steam stimulation and should be investigated further later.
2. Thermal reaction tests for shanjiasi crude in the laboratory demonstrated that injected steam cracked the oil into the following:

   heavy crude → gas, light oil, and coke

   Regarding these products, light ends and gas made the produced oil lighter, but the amount of the heavy ends (coke), however, is significant, as this is especially true as the temperature exceeds 350°C. In the future, the steam injection pressure should be controlled at a certain level in order to optimize the heat content in steam, and also to reduce the chance of producing coke.
3. The $NaHCO_3$ type of water was supplied for steam generation. Decomposition of such water in the boiler could increase the in-situ crude with high acids and result in water in oil emulsion. This product with high viscosity certainly is adverse to steam stimulation. Therefore, it is suggested that we should accelerate developing the high temperature proof TFSA, and add a proper amount of additives in the water to moderate its pH value for steam generation.

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2. Jiang, J.L., Shi, X.L., "High Performance Liquid Chromatography of Reversed Phase in the Analysis of Aromatic Hydrocarbon from Crude Oil," Chromatography 1990, vol. 8, no. 5, pp. 269–272.
3. Duerksen, J.H. and Hsueh, L., "Steam Stillation of Crude Oil," Paper SPE 10070.

Table 7. Reflectory index

Sample no.	Temperature °C	Isotherm period hr.	Reflectory index
Asphaltene-1	350	24	1.85
Asphaltene-2	350	48	1.87
Asphaltene-3	350	72	2.23
Asphaltene-4	350	96	2.28
Asphaltene-5	350	120	2.36

Table 8. Shanjiasi crude emulsion simulation test

Oil sample mL	Water sample mL	Water sample name	Water sample pH	Type of water	Temp °C	Mixing time hr.	Pressure MPa	Type of emulsion	Viscosity at 80°C, mPa·s		
									Original	Emulsion	Ratio
200.00	130.0	Boiler outlet	12.26	$NaHCO_3$	300	12	9.7–10	w/o	352	1300	2.163
200.00	130.0	Boiler inlet	8.71	$NaHCO_3$	300	12	9.7–10	w/o	352	964	2.740

A LABORATORY STUDY OF MISCIBLE DISPLACEMENT IN A SASKATCHEWAN LIGHT OIL OF RESERVOIR

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Saskachewan Research Council, Petroleum Research, Regina, Saskatchewan, Canada

ABSTRACT

Most of Saskatchewan's light and medium oil (LMO) reservoirs have reached economic limits of production under waterflooding leaving seventy to eighty percent of the initial oil-in-place (IOIP) in the reservoirs. The miscible displacement process using carbon dioxide, hydrocarbon and other gases as solvents appears to be one of the most promising methods for these reservoirs.

A laboratory study was conducted to evaluate the applicability of various solvents for the recovery of oil from a southeast Saskatchewan reservoir. The physical, chemical, and phase behaviour (PVT) properties of wellhead and reservoir fluids were determined.

Slim tube displacement tests were conducted between the reconstituted Pinto Reservoir fluid and carbon dioxide, ethane and wellhead gas from the Steelman gas plant as solvents at various pressures and the reservoir temperature of 56°C.

The minimum miscibility pressures (MMP) determined for the above three systems demonstrated that the MMP For ethane is much lower than that for carbon dioxide, which is lower than that for Steelman gas. The MMP for ethane and carbon dioxide are below the reservoir fracture pressure.

INTRODUCTION

Most of Saskatchewan's light and medium oil (LMO) reservoirs have reached their economic limit of production under current technology. Primary and secondary methods together recover about 21% of the initial oil-in-place (IOIP). Although the remaining light and medium oil-in-place in Saskatchewan is 1135 million cubic metres, the remaining producible reserves under primary and secondary recovery are only 65 million cubic metres.[1] Medium oil in southwest Saskatchewan has not been considered here, but if it is included then up to 17 million cubic metres of additional oil (through primary and secondary recovery) may be recovered.[1]

The development of tertiary recovery techniques, therefore, is essential to increase the production life of these reservoirs and to maintain current production. Application of the miscible oil displacement process using CO_2, hydrocarbon and other gases as injection fluids is expected to increase the LMO reserves threefold and extend the production life of these pools by two decades.[2]

Miscible flooding with carbon dioxide and hydrocarbon solvents is considered to be one of the most effective enhanced oil recovery (EOR) processes applicable to LMO reservoirs. Current industry interest in CO_2 miscible flooding is high, as evidenced by the level of activity in field testing[3] and CO_2 scurce development in the United States.

It should be noted that since the world oil price collapse in 1986, the number of EOR projects in the United States has decreased markedly from 512 in 1986 to 366 in 1988 and to 295 in 1990. But, the number of CO_2 miscible projects increased from 38 in 1986 to 49 in 1988 and to 52 in 1990, which indicates a steady rise during these four years.[3,15] Oil production in early 1988 by the CO_2 miscible process showed a 125% increase over the same period in 1986. Similarly, the production in early 1990 from this process increased by 49% (over the same period in 1988).

In spite of the great potential of the CO_2 process and the growing number of field CO_2 projects, the mechanisms of CO_2/crude oil displacement are not understood fully.[4] Interactions among the oil, CO_2

and water phase, and the recovery of the reservoir oil have been interpreted largely from knowledge and experience previously gained from waterflooding and hydrocarbon injection, which may not be valid in the case of CO_2 flooding.

Miscible displacement between crude oil and CO_2 is caused by the extraction of hydrocarbons from the oil into the CO_2 and by dissolving CO_2 into the oil. Light and intermediate molecular weight hydrocarbon fractions, as well as the heavier, gasoline and gas oil fractions are vaporized into the CO_2 front. Consequently, vaporizing-gas drive miscibility with CO_2 can occur with little or no C_2 to C_6 components present in the crude oil. Miscibility between the oil and CO_2 eliminates interfacial tension and capillary forces and could help recover essentially all of the residual oil.

Miscible recovery of a reservoir oil can be achieved by CO_2 or hydrocarbon displacement at a pressure level greater than a certain minimum.[5] This minimum pressure, defined as the minimum miscibility pressure (MMP), has been used as one of the most essential criteria for screening and selecting reservoirs for the miscible oil displacement process. A candidate reservoir must be capable of withstanding an average reservoir pressure greater than the MMP.

For the CO_2 injection projects, it has been well recognized that the CO_2 MMP for a reservoir oil depends upon the purity of CO_2, oil composition and reservoir temperature.[6,12] In general, the presence of CH_4 or N_2 in CO_2 can substantially increase the CO_2 MMP, while the presence of H_2S, C_2H_6 or intermediate hydrocarbons (such as C_3, C_4) can reduce the CO_2 MMP.[8–10] The minimum miscibility pressure normally increases with increasing reservoir temperature.[6,7] A substantial oil compositional effect on MMP has been observed by several investigators.[10–13]

There are many technical questions remaining that would affect the applicability of the CO_2 miscible process to Saskatchewan reservoirs:

- level of impurities present in CO_2
- precipitation of solid organic materials (such as asphaltenes) in the reservoir
- CO_2 injection rate, slug size and CO_2 water-alternating gas (WAG) ratio
- wettability changes and acidic effects on the rock
- water blocking of oil due to the presence of water in portions of the pore space
- viscous instabilities, gravity segregation, and
- heterogeneity of the reservoir rock.

All of these can strongly influence the process performance and, therefore, they must be answered before a field project can be successfully implemented. These concerns, however, are beyond the scope of this investigation and will not be discussed here.

The objective of the work presented in this paper is to conduct experimental PVT and slim tube tests to screen suitable solvents and to develop optimum operating conditions for application of miscible flooding to Saskatchewan reservoirs. A light oil from the Pinto Reservoir in southeast Saskatchewan was used for the studies.

Pinto (Middle Beds, Non-unit) Geology and Reservoir Description

The Pinto pool is located approximately 50 kilometres east of Estevan, Saskatchewan. The entire pool has a NE-SW orientation. First drilled in the early 1960's, the pool produces 35–39°API oil from the Mississippian Midale and Frobisher beds with most oil coming from the Midale Vuggy zone.

The trapping mechanism in the Midale beds is stratigraphic because the oil is contained within a generally NE-SW permeability trend. In the oil producing wells, the Midale beds contain numerous organic grains in a dolomitic limestone matrix. The Pinto (Midale beds, non-unit) reservoir contains approximately 11.6 x 106 m^3 of the initial oil-in-place.

A summary of the production and reservoir data is presented in Table 1. For this study, the wellhead oil and separator gas samples were collected from well 7-12-2-5 W2M. The Pinto Reservoir fluid was reconstituted by recombining the centrifuged wellhead oil and separator gas to a bubble point pressure of 10.31 MPa at 56°C (reservoir temperature).

*Table 1. Summary of production and reservoir data – Pinto Midale beds, non-unit**

Reserves	Initial oil-in-place (IOIP), m^3	11.646 x 106
	Estimated primary recovery, %OOIP	6.9
	Estimated secondary recovery, %OOIP	0.0
	Total, %OOIP	6.9
	Recovery to 31-12-1987, %OOIP	4.8
Production	Cumulative (to 31-12-1987), m^3	562.000
	Yearly total (1987), m^3	40,336
	Daily averages (1987), m^3	111
Reservoir data	Discovery year	1960's
	Producing horizon	Midale (non-unit)
	Developed area, ha	3543
	Average reservoir depth, m	1625**
	Initial reservoir pressure, MPa	17.24
	Initial reservoir temperature, °C	70 (56)**
	Average net pay, m	6.3
	Average porosity, %	10.7
	Average connate water, %	35.0
	Oil density, kg/m^3	834

* Saskatchewan Energy and Mines, Reservoir Annual 1987, Miscellaneous Report 87-1

** Well 7-12-2-5 W2M

EXPERIMENTAL

Crude Oil Characterization and Separator Gas Analysis

The wellhead oil and separator gas samples from well 7-12-2-5 W2M in the Pinto Reservoir collected in August 1985 were used for this study.

The density of the dead oil was measured at four temperatures using the Anton Paar DMA 45 and DMA 512 density meters. The viscosity of the oil was measured at three temperatures by a Brookfield HBTDCP 1.565 degrees cone and plate model CP-42 viscometer. The pressure-density relationships of the oil were determined at 56°C in the high-pressure Anton Paar densitometer.

The composition of the oil and separator gas was determined by gas chromatography.

Light Oil PVT Apparatus

The light oil PVT apparatus is shown schematically in Figure 1. The PVT cell is constructed of 17-4 Ph stainless steel and the end caps of 316 stainless steel. The cell liner is glass. This heavy wall glass cylinder is encapsulated in such a manner that the internal fluid pressure is always balanced by external overburden pressure. Since the net force on the cylinder is zero, there is no expansion of the cell with an increase in pressure. The seals for the end cap are Viton o-rings and for the window, glass-filled teflon. The cell volume is approximately 125 cm^3.

A cathometer is included in the system to monitor the phase boundary and to measure the system volume. Oil and gas phase volumes are easily determined.

With this equipment, the observation of phase behaviour and the measurement of equilibrium phase compositions for two or more fluid phases can be carried out. The PVT properties of the petroleum fluids, including the saturation pressure, gas-oil ratio, formation volume factor, and swelling factor are routinely determined in the apparatus.

The pressure and temperature readings of this apparatus are 68.9 MPa and 200°C.

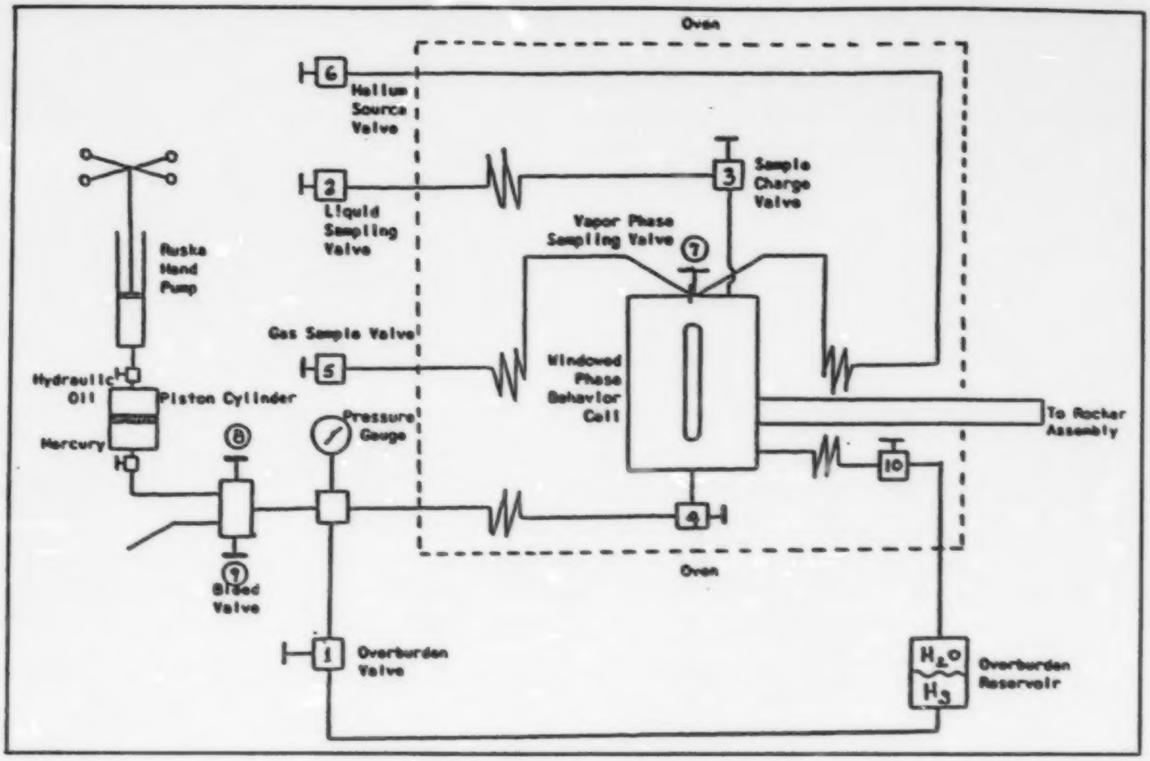
Oven
6
Helium Source Valve
2
Liquid Sampling Valve
3
Sample Charge Valve
Vapor Phase Sampling Valve
7
Ruska Hand Pump
Gas Sample Valve
5
Windowed Phase Behavior Cell
Hydraulic Oil
Piston Cylinder
Mercury
8
Pressure Gauge
To Rocker Assembly
10
4
9
Bleed Valve
Oven
1
Overburden Valve
H_2O
Hg
Overburden Reservoir

Figure 1. Light oil PVT apparatus.

PVT Measurements

The bubble point pressure of the recombined fluid was determined by measuring its pressure-volume relations (through constant composition expansions) on the equipment described above and obtaining the best fit from a Y-function* versus pressure plot. Determination of the bubble point of a mixture commenced at a pressure higher than the estimated bubble point. The procedure ensures that a single phase exists in the cell. The volume of the cell was then increased and the change in pressure recorded after a constant value was reached. This procedure was continued until the total volume of the oil and gas at their pressure relative to the volume of the oil at the saturation pressure was about 1.4.

The saturation pressure (P_{sat} and the oil volume at P_{sat} was initially estimated from the P-V relationship. Several Y-function versus pressure plots were then established. The saturation pressure was determined by the best fit of these plots. Normally, a linear relation is obtained at the saturation pressure.

For a density determination as a function of pressure above the bubble point, the recombined fluid was initially transferred from the PVT cell to a 10-cm^3 minimum equipped with a Bourns pressure transducer. This single phase fluid was then charged into the high-pressure Anton Paar density meter DMA 512 cell and its density measured at the reservoir temperature.

The viscosity of the recombined fluid as a function of pressure was determined using a Ruska rolling ball viscometer.

The gas-oil ratio, formation volume and swelling factors, and the composition of the oil and gas phases were determined by withdrawing a known volume of the single phase fluid in a sampling bottle. The oil was accumulated in the bottle and the gas was collected in a gasometer. The oil collected was weighed, the gas volume was recorded and its composition analyzed by a gas chromatograph. From the known volume of the sample collected at cell conditions and the weight of the oil and gas fractions collected, the gas-oil ratio (GOR), formation volume and swelling factors were calculate

Slim Tube Apparatus and Procedures

The slim tube apparatus is shown in Figure 2. The main features of the equipment include a constant rate positive displacement pump, a stainless steel slim tube packed with sand, a differential pressure transducer for measuring the pressure drop across the slim tube, a capillary sight glass for the detection of the phase boundary and colour change of the fluid in the transition zone, a gas-liquid separator for oil-gas separation and produced oil collection, a wet test meter for continuous gas volume measurement and an "on-line" gas chromatograph for carrying out the compositional analysis of the produced gas.

An "on-line" high-pressure densitometer has since been incorporated in the slim tube system to monitor the fluid density change in the transition zone. This densitometer is a valuable tool as it not only allows accurate density measurements of the reservoir oil, injection solvent and their mixtures, but also provides precise determination of the arrival time of the transition zone during the slim tube experiment.

The slim tube properties are presented in Table 2. Displacements were carried out in a 12.2-m long, 0.457-cm i.d. stainless steel column packed with 75–106 mm Ottawa sand. The porosity was estimated to be 43.9% and the permeability 6 darcies. The pressure and temperature readings are 34.5 MPa and 200°C.

In preparation for an experiment, at least three pore volumes of toluene was pumped through the slim tube for cleaning. The back-pressure regulator was then carefully adjusted to the desired pressure using either helium or nitrogen for the gas side and toluene

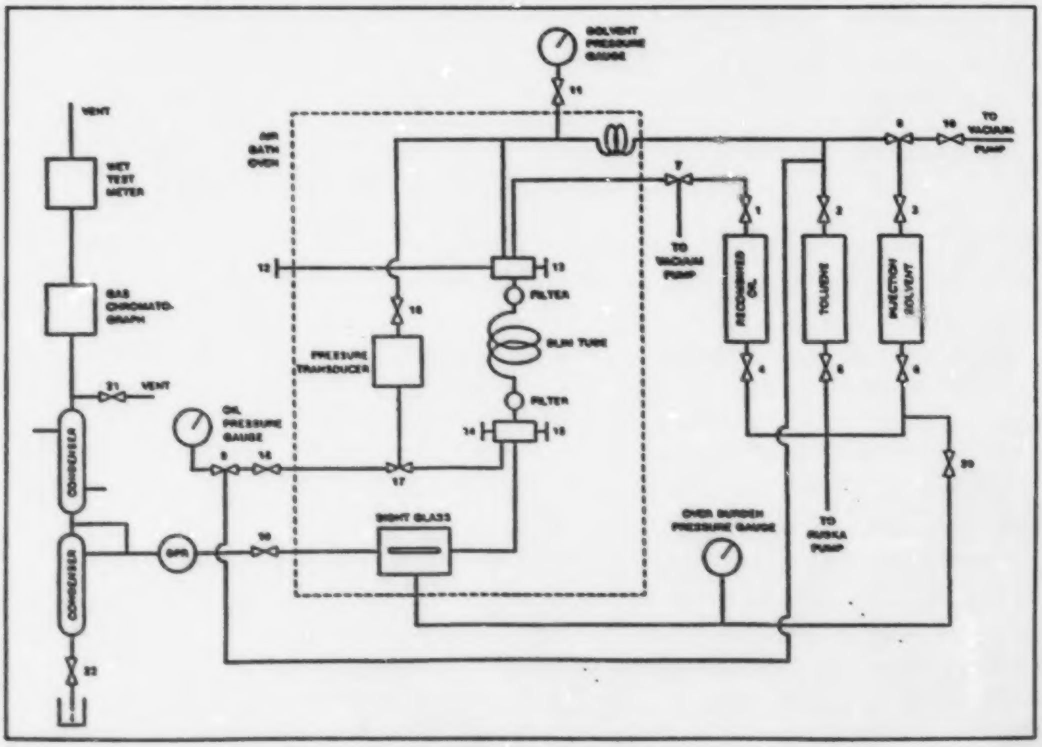
SOLVENT PRESSURE GAUGE
11
VENT
AIR BATH OVEN
WET TEST METER
8
10
TO VACUUM PUMP
7
1
2
3
12
13
TO VACUUM PUMP
RECOMBINED OIL
TOLUENE
INJECTION SOLVENT
FILTER
GAS CHROMATO-GRAPH
16
SLIM TUBE
PRESSURE TRANSDUCER
4
5
6
21
VENT
FILTER
OIL PRESSURE GAUGE
14
15
9
18
17
20
CONDENSER
SIGHT GLASS
OVER BURDEN PRESSURE GAUGE
TO RUSKA PUMP
CONDENSER
BPR
19
22

Figure 2. Slim tube apparatus.

Table 2. Slim tube properties

Column material	316 stainless steel
Length, m	12.2
Internal diameter, cm	0.457
Packing material	Ottawa silica sand
Diameter, mm	75–106
Porosity, %	43.9
Permeability, μm^2	6
Pore volume, cm^3	88.1
Pressure rating, MPa	34.5
Temperature rating, °C	200

for the liquid side. About two pore volumes of the reconstituted reservoir fluid were pumped into the slim tube to displace toluene. A single stage flash separation test was occasionally carried out to ensure the reservoir fluid was representative. The gas solvent cylinder was mounted in the oven and the system was then heated up to the desired temperature.

The gas solvent was injected into the slim tube to contact and displace the reservoir oil using a positive displacement pump at a rate of 3.75 cm^3/h.

Injection and production pressures, as well as the differential pressure across the slim tube, were continuously monitored during the experiment. The high pressure capillary sight glass, installed at the outlet of the slim tube, was used for visual observation of the fluid-fluid interface and the colour changes of the fluid indicative of the transition zone. The effluent was flashed to atmospheric conditions at the back-pressure regulator. It was then passed through a condenser, cooled by circulating water, into a gas-liquid separator. The produced liquid was collected in a graduated cylinder and weighed. The produced gas was passed through a gas chromatography (GC) sampling assembly for compositional analysis, and then through a wet test meter for volume measurement.

Data were taken once every half hour. After 1.3 pore volumes of solvent injection, the run was terminated. Typically one slim tube experiment takes about 32 hours.

Materials

Research purity carbon dioxide (99.995% minimum) and commercial purity ethane (99.0%) were obtained from Matheson Gas Products. These gases were used as received.

RESULTS AND DISCUSSION

PVT properties

Crude oil characterization and separator gas analysis. Wellhead oil and separator gas samples were collected from well 7-12-2-5 W2M in the Pinto Reservoir. The density of the oil was measured at 15, 20, 25 and 40°C and the viscosity at 20, 25 and 40°C. The pressure dependence of the density of the oil at 56°C was determined. The data along with the molecular weight of the oil are reported in Table 3. The density and viscosity of the wellhead oil decreased with temperature and its density increased with rising pressure. At 20°C, the density and viscosity of the oil were 834.6 k/m^3 and 4.34 mPa·s, respectively.

The simulated distillation data and carbon number distribution of the dead oil, and the

Table 3. Chemical and physical properties of Pinto dead oil

Temperature °C @ 95 KPa	Density kg/m^3	Viscosity mPa·s
15	838.2	–
20	834.6	4.34
25	831.1	3.67
40	820.5	2.42
Pressure, kPa @ 56°C		
95	812.3	
3540	815.2	
6990	818.4	
10440	821.3	
13890	824.1	
17340	827.0	
20780	829.0	
24230	832.8	

composition of the separator gas are listed in Tables 4–6. The amount of 525°C+ residue fraction in the crude oil is 5.5 percent by volume and the C30+ fraction of the dead oil is 8.66 percent by weight.

*Table 4. Simulated distillation data for Pinto crude oil**

Volume percent distilled	Temperature (°C)	Volume percent distilled	Temperature (°C)
IBP	33	55	285
5	89	60	309
10	101	65	335
15	116	70	361
20	129	75	389
25	150	80	419
30	171	85	449
35	192	90	484
40	216	95	530
45	238	FBP	
50	261		

Boiling range (°C)	Volume percent
IBP–204	37.6
204–343	28.9
343–525	28.0
525 + residue	5.5

* A flashed reservoir oil. Simulated distillation by gas chromatography.

Table 5. Carbon number analysis of Pinto dead oil

Component	Composition		Component	Composition	
	wt%	mol%		wt%	mol%
Ethane	0.06	0.34	C_{16}	5.48	4.13
Propane	0.22	0.85	C_{17}	4.70	3.35
i-Butane	0.09	0.27	C_{18}	2.19	1.96
Butane	0.42	1.23	C_{19}	2.65	1.69
i-Pentane	0.31	0.73	C_{20}	2.51	1.52
Pentane	0.71	1.69	C_{21}	2.27	1.31
C_6	1.87	3.7	C_{22}	2.09	1.14
C_7	8.75	11.52	C_{23}	1.79	0.94
C_8	10.17	15.23	C_{24}	1.59	0.80
C_9	8.70	11.61	C_{25}	1.46	0.70
C_{10}	6.86	8.25	C_{26}	1.31	0.61
C_{11}	5.57	6.10	C_{27}	1.19	0.53
C_{12}	5.05	5.07	C_{28}	1.08	0.46
C_{13}	4.13	3.82	C_{29}	0.22	0.09
C_{14}	4.99	4.30	C_{30+}	8.66	2.63
C_{15}	4.21	3.40			

Reservoir fluid characterization. The Pinto wellhead oil and separator gas were recombined at 56°C to a saturation pressure of 10.31 MPa to reconstitute the reservoir fluid. This fluid was used for the PVT and slim tube miscibility studies.

A PVT study on the reconstituted reservoir fluid was conducted in the light oil PVT apparatus. From a flash liberation test of the reservoir fluid, the formation volume factor (FVF) and gas-oil ratio (GOR) were determined to be 1.16 and 56.5 m³/m³, respectively (Table 7). (The formation volume factor is defined as the ratio of the fluid volume at the saturation pressure and 56°C to the stock tank oil volume at 15°C.) The liberated gas had a specific gravity of 0.854.

The pressure dependence of the viscosity and the density of the reservoir fluid were measured, and their values at the saturation pressure are 1.16 mPa·s and 771.2 kg/m³, respectively (Figures 3 and 4).

The compressibility of the fluid at 56°C was measured

Table 6. Separator gas analysis – Pinto

Component	Mol %
N_2	2.28
CO_2	0.06
H_2S	2.18
Methane	67.18
Ethane	15.04
Propane	7.61
i-Butane	0.90
Butane	2.30
i-Pentane	0.45
Pentane	0.57
$C_{6}+$	1.44

Table 7. Physical properties of the reconstituted Pinto reservoir fluid at 56°C

Properties	
Saturation pressure, MPa	10.31
Viscosity, mPa·s @ P_{sat}	1.16
Density, kg/m^3 @ P_{sat}	771.2
Formation volume factor,[a] m^3/m^3	1.162
Gas-oil ratio,[b] m^3/m^3	56.5

[a] Formation volume factor = $\frac{\text{Volume of reservoir fluid @ Psat and 56°C}}{\text{Volume of reservoir oil @ 1 atm and 15°C}}$

[b] Cubic metres of gas at 101.325 kPa and 15°C per cubic metre of stock tank oil at 15°C.

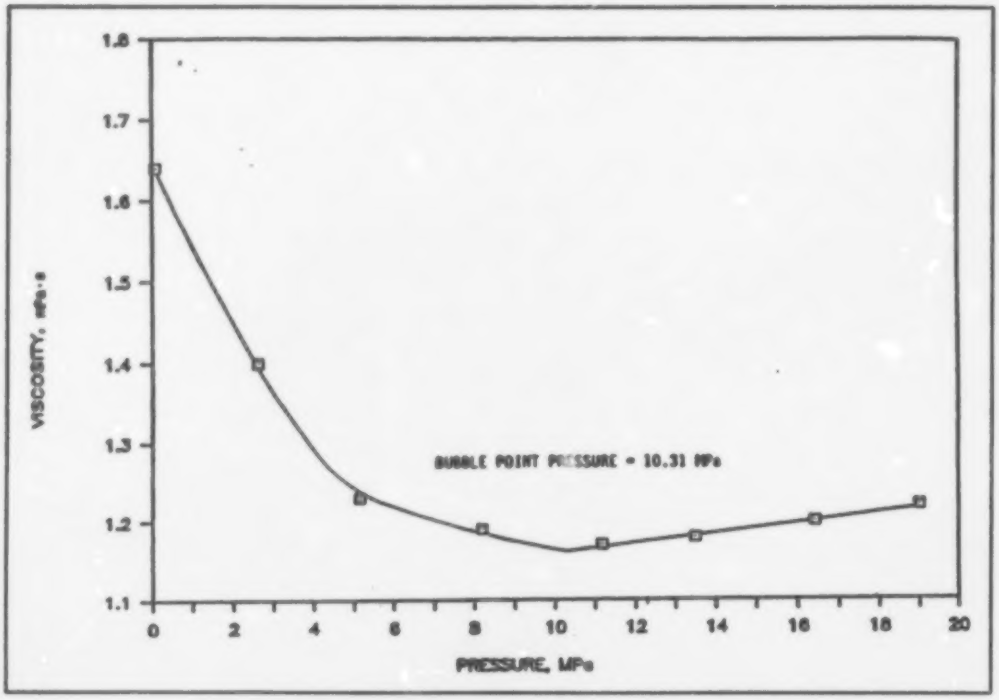

Figure 3. Viscosity-pressure relations for Pinto Reservoir at 56°C.

to be $1.2 + 0.2 \times 10^{-3}$ vol/vol/MPa between 10.31 MPa and 17.77 MPa (Table 8).

Slim Tube Miscibility Studies

The Saskatchewan Research Council (SRC) slim tube apparatus, displacement procedures and measuring methods are similar to those reported by Yellig and Metcalfe.[7] Displacement tests were carried out to determine the minimum miscibility pressures (M) of the reservoir oil-injection solvent systems using the sand-packed coil. The purpose of using a sand-packed coil was to provide a medium for mixing gas solvent and oil in a flowing, multiple

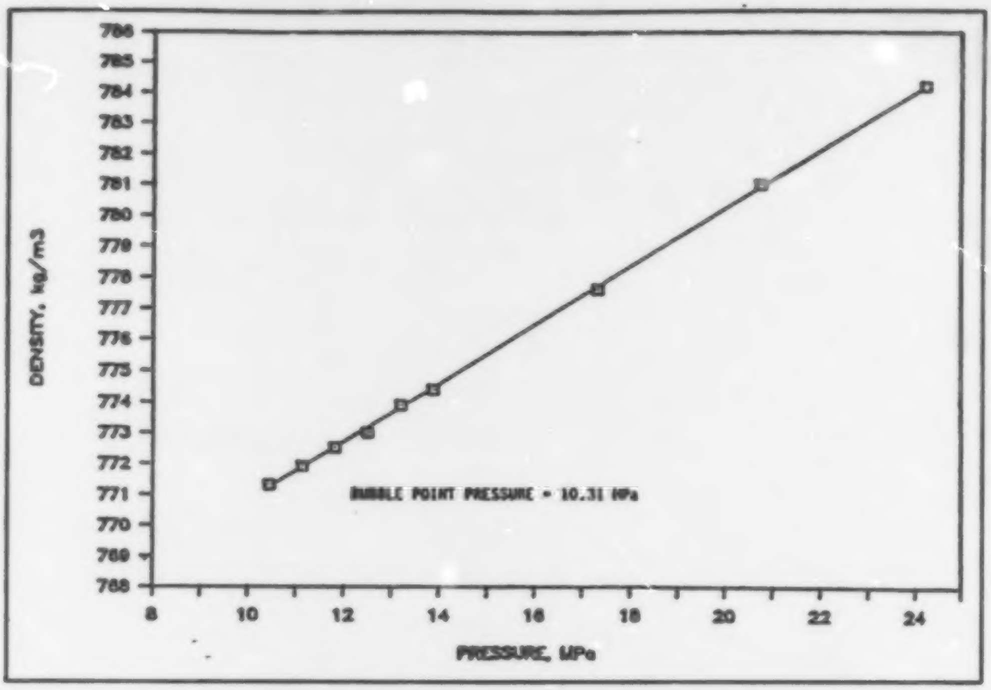

Figure 4. Density-pressure relations for Pinto Reservoir at 56°C.

Table 8. Compressibility of Pinto reservoir fluid at 56°C

Pressure range (MPa)	Compressibility (vol/vol/MPa)
17.77 to 14.69	1.01×10^{-3}
14.69 to 12.28	1.15×10^{-3}
12.28 to 10.31	1.38×10^{-3}

Table 9. Steelman gas composition

Component	Mol%
N_2	3.97
CO_2	1.24
H_2S	0.89
Methane	56.67
Ethane	18.50
Propane	12.56
i-Butane	1.38
Butane	3.10
i-Pentane	0.50
Pentane	0.47
C_6^+	0.59

contact process. It was not intended to simulate reservoir rock and fluid mobility properties. Data obtained from these tests were used only to distinguish miscible from immiscible displacements. The MMP is the minimum pressure at which the injection solvent can generate miscibility with the test oil through a multiple contact process.

The data collected in the slim tube experiments were:

(1) pressure drop across the tube
(2) solvent injected (pore volume)
(3) oil produced (volume or weight)
(4) gas produced (volume)
(5) gas-oil ratio (m^3/m^3)
(6) light ends (H_2S C_1–C_5) concentration in the produced gas (mol%)
(7) CO_2 concentration (mol%).

Reservoir fluid and Steelman gas. Slim tube miscibility tests were performed on the Pinto

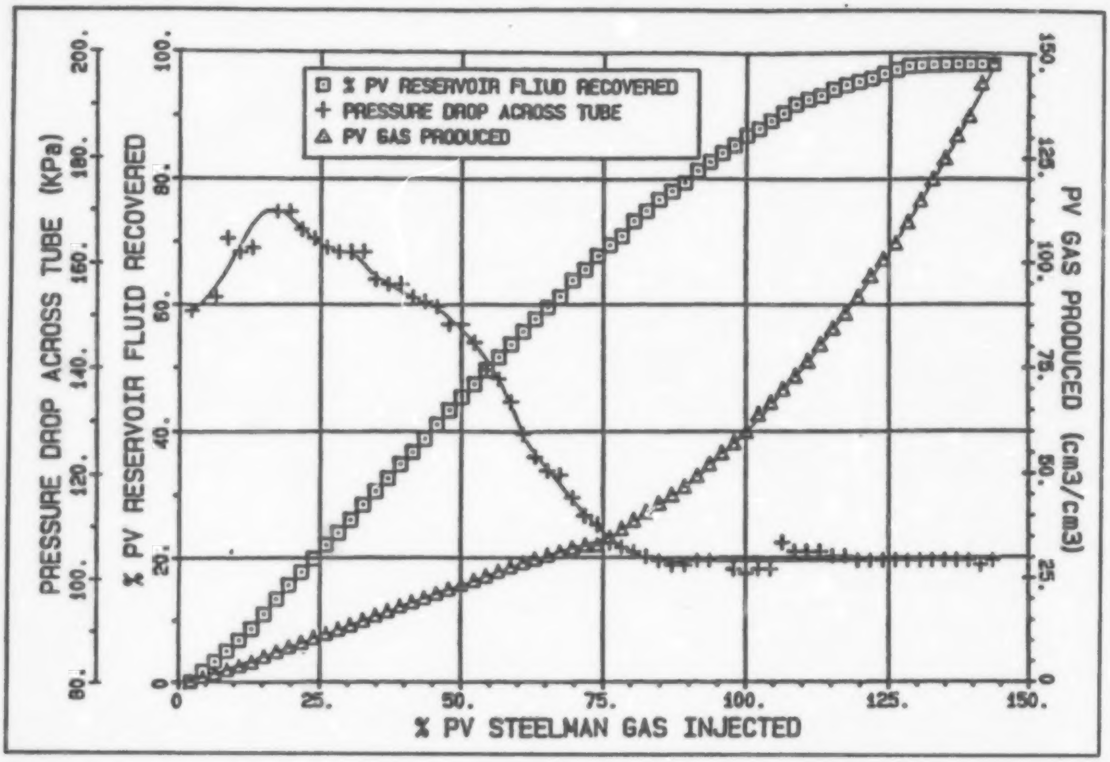

Figure 5. Slim tube experimental results for Pinto Reservoir fluid/Steelman gas system at 27.76 MPa and 56°C.

Reservoir fluid with Steelman gas at 56°C and five pressures ranging from 13.9 MPa to 27.8 MPa. The Steelman gas is a relatively rich solvent with its composition presented in Table 9. Figure 5 illustrates the experimental results obtained for the reservoir fluid/Steelman gas system at 27.8 MPa and 56°C. The test run was concluded to be miscible with an oil recovery of 95.6% of the initial oil-in-place (IOIP) at 1.2 PV Steelman gas injected. No early gas breakthrough was detected. Visual observations of the sight glass showed no phase boundary in the transition zone. A smooth colour change was observed from the dark brown Pinto oil to reddish brown, then to orange, yellow and finally to colourless injection fluid. The flashed gas compositions showed no methane bank prior to solvent breakthrough.

The recovery data from the slim tube tests for the Pinto Reservoir fluid with Steelman gas at five pressures are summarized in Table 10. The oil recovery versus pressure plots are illustrated in Figure 6. The MMP was defined to be that point at which a break-over in the recovery versus pressure curve occurred and the displacement appeared to be miscible by sight glass observation (i.e. no two-phase flow).[7,10]

Table 10. Summary of Pinto slim tube test results at 56°C

Solvent	Pressure MPa	Oil recovered, % IOIP 1.0 PV Injected	 1.2 PV Injected
CO_2	10.70	52.7	58.3
	13.78	69.4	80.3
	17.23	87.1	94.5
	20.68	91.1	100.0
Steelman gas	13.86	43.9	49.8
	17.34	68.1	77.3
	20.89	77.0	85.9
	24.89	83.5	92.7
	27.76	86.9	95.6
C_2H_6	11.12	91.7	96.4
	13.88	81.2	95.1
	17.33	85.4	96.6

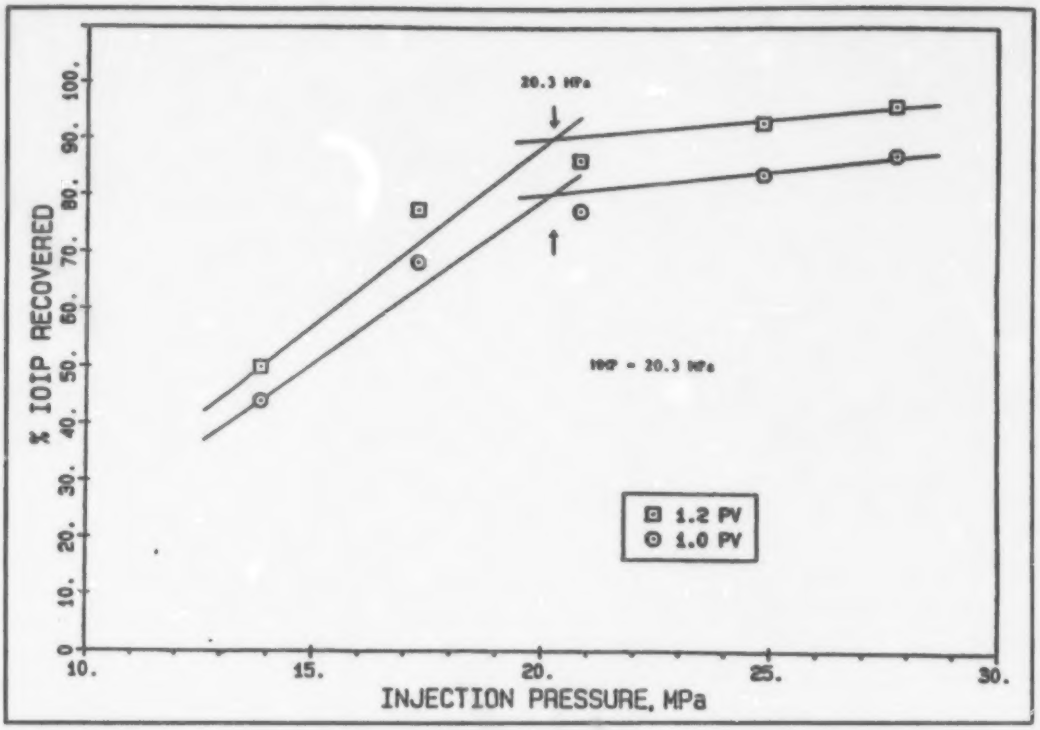

Figure 6. Oil recovered versus pressure at various pore volumes of Steelman gas injected.

The minimum miscibility pressure for the Pinto Reservoir fluid with Steelman gas was estimated to be 20.3 MPa at 56°C (Figure 6 and Table 11). This MMP is slightly lower than the reservoir fracture pressure.

Table 11. Minimum miscibility pressures for Pinto reservoir fluid/injection solvent systemat at 56° C

Solvent	MMP (MPa)
CO_2	16.0
Steelman gas	20.3
C_2H_6	10.3

Reservoir fluid and carbon dioxide. For the Pinto Reservoir fluid-CO_2 system, slim tube experiments were completed at four pressures ranging from 10.7 MPa to 20.7 MPa. Figure 7 illustrates the oil recoveries as a function of pore volumes CO_2 injected at various pressures. The % IOIP recovered at 1.0 PV and 1.2 PV CO_2 injected at four pressures are given in Table 10.

The oil recovery versus pressure plots are shown in Figure 8. The MMP for the Pinto Reservoir fluid with CO_2 at 56°C is estimated at 16.0 MPa and is lower than the reservoir fracture pressure. Therefore, carbon dioxide is demonstrated to be a good solvent for the miscible recovery of light and medium oil in southeast Saskatchewan reservoirs.

Reservoir fluid and ethane. Slim tube tests were conducted for the Pinto Reservoir fluid with ethane at 56°C at three pressures between 11.1 MPa and 17.3 MPa. Figure 9 demonstrates the % IOIP recovered at 1.0 PV and 1.2 PV C_2H_6 injected as a function of pressure.

For the Pinto Reservoir oil-C_2H_6 system, high oil recoveries were obtained at all pressures conducted (Table 10 and Figure 9). The MMP for C_2H_6 was below the bubble point pressure (BPP) of the reservoir

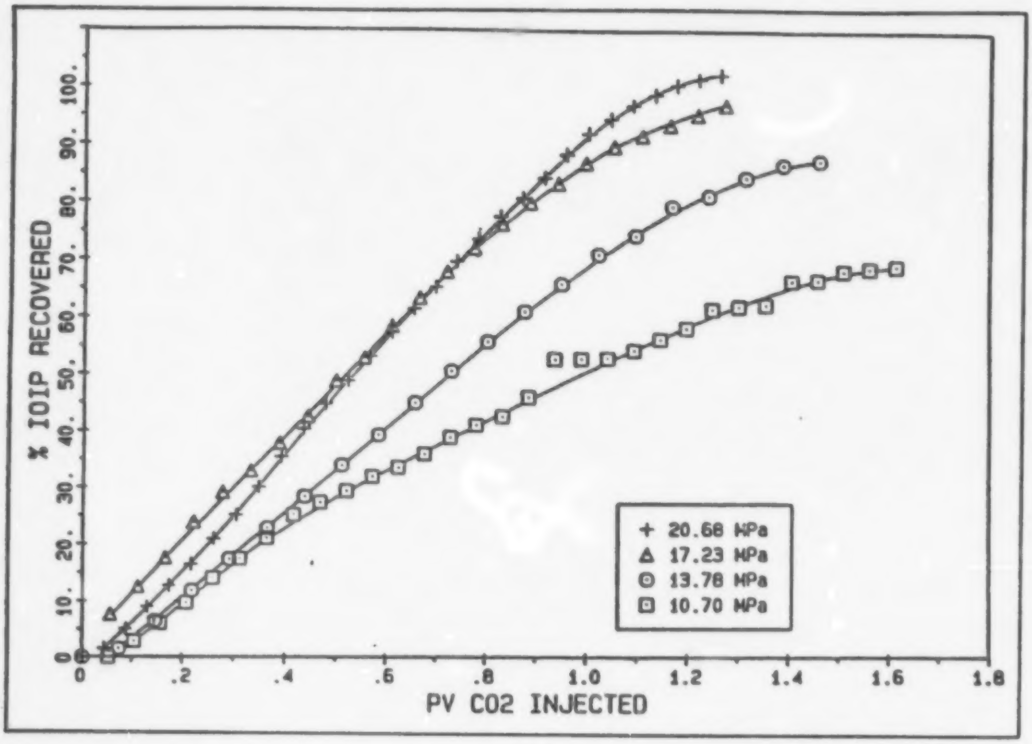

Figure 7. *Oil recovered versus PV CO_2 injected in Pinto oil at various pressures at 56°C.*

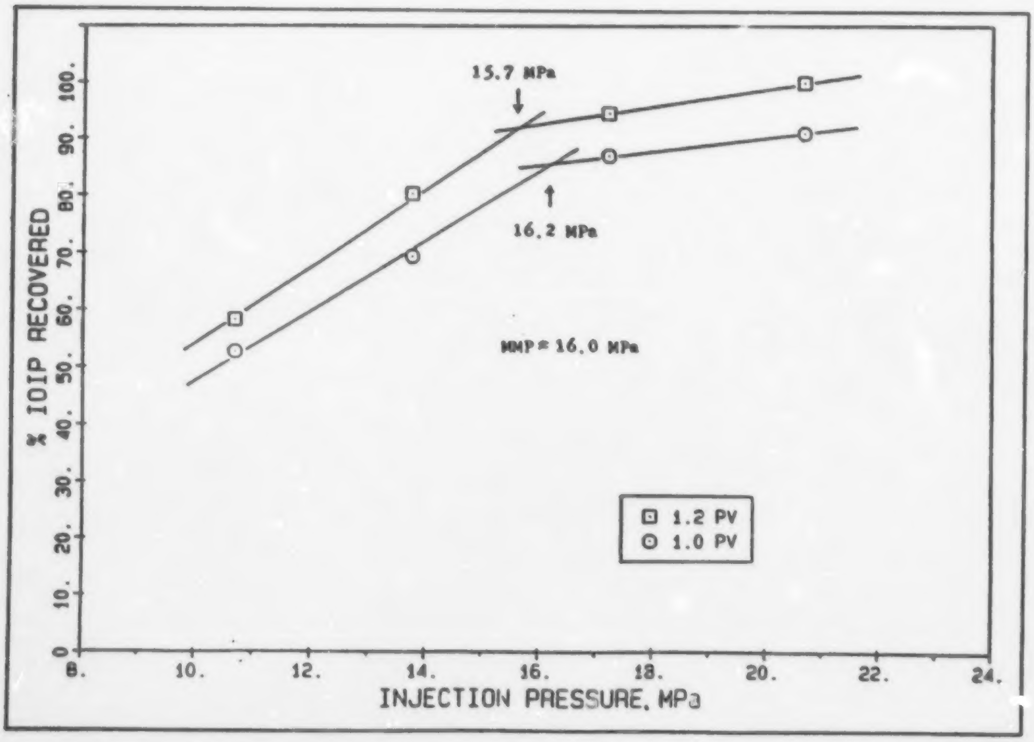

Figure 8. *Oil recovered versus pressure at various pore volumes of CO_2 injected in Pinto oil.*

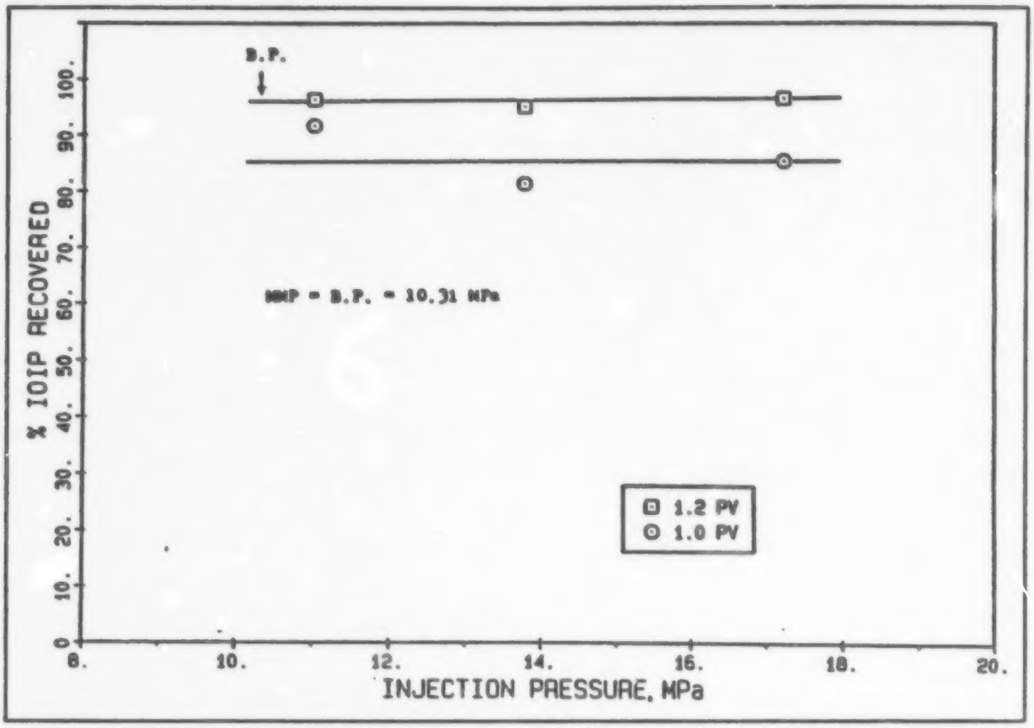

Figure 9. Oil recovered versus pressure at various pore volumes of C_2H_6 injected in Pinto oil.

oil, therefore, the MMP of the system was set equal to the BPP10 which was 10.31 MPa. Since an oil is not tested below its BPP, the MMP determined must be at least as great as the BPP of the oil.[7,10]

Although ethane (C_2H_6) was shown to a more effective solvent than CO_2 in the slim tube miscibility study, work on core displacement of the reservoir oil by CH_6 is required to confirm the process for field application. In addition, when considering the use of CH_6 as a solvent in replacing CO_2, a number of questions will need to be addressed.

Gravity override may be more severe with C_2H_6 than with CO_2.[14] In Saskatchewan heavy and medium oil reservoirs, C_2H_6 as an injection solvent at reservoir conditions (pressure and temperature) is less dense than CO_2. Ethane would, therefore, be more prone to gravity override and would contact less residual oil in the reservoir.[14]

At reservoir conditions, C_2H_6 dissolves less than CO_2 in the formation water. The benefit from allowing solvent contact with the residual oil through water (reducing the effects of water shielding) would not be as noticeable with C_2H_6 as with CO_2.[14]

Ethane is not as readily available in Saskatchewan as it is in Alberta. The purchase costs, therefore, would be high. On the other hand, carbon dioxide could come from the United States where a cheaper source can be supplied.

SUMMARY AND CONCLUSIONS

The density and viscosity of the Pinto wellhead oil and the reconstituted Pinto Reservoir fluid increased with rising pressure, and these values decreased with temperature.

The minimum miscibility pressures (MMP) for the Pinto Reservoir fluid with carbon dioxide, with ethane and with the wellhead gas from the Steelman gas plant were determined. The obtained data indicated that the MMP for ethane is much lower than that for carbon dioxide, which is lower than that for Steelman gas. The MMP for ethane and carbon dioxide are well below the reservoir fracture pressure.

The slim tube studies demonstrated that the miscible displacement process using carbon dioxide or ethane as a solvent is a promising EOR technique for southeast Saskatchewan reservoirs. The wellhead gas from the Steelman gas plant would require further enrichment.

Ethane (C_2H_6) when used as a solvent for the Pinto Reservoir was demonstrated to be more effective than CO_2 in achieving miscibility with oil. There are, however, a number of potential problems associated with the use of C_2H_6 (gravity override, low solubility in water, availability and high cost).

ACKNOWLEDGEMENT

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AWACT: ANTI-WATER CONING TECHNOLOGY

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ABSTRACT

It is estimated that over 50% of Alberta oil fields experience excessive water production, resulting in lost recovery from early abandonment of wells. To minimize the adverse effect of water production, operators have tried to physically block the water through injection of cement, polymer, foam, and other chemical agents. These techniques generally have met with mixed success and have the reputation of being unreliable. Alberta Energy Company Ltd. (AEC) and Westcoast Petroleum Ltd., with technical and financial support from the Alberta Oil Sands Technology and Research Authority (AOSTRA), have developed a simple process, called Anti-Water Coning Technology (AWACT), for inhibiting water production and have field tested its applicability in a heavy oil water coning environment. Laboratory tests and reservoir simulation have been used to develop a theoretical basis for the process mechanisms. This paper describes the process and treatment procedure and shows long term field results to demonstrate both acceleration of production and increase in recovery. AEC considers AWACT to be commercially viable in their South Jenner field for wells producing water at unacceptable levels.

INTRODUCTION

Excessive water production due to bottom water coning is a widespread oilfield problem and is especially prevalent where the water mobility greatly exceeds the oil mobility. If unchecked, the problem may result in poor oil recoveries because pumping high water:oil ratios ultimately becomes uneconomical. Faced with the prospect of suspending or abandoning high water cut oil wells, operators can resort to a number of remedial methods to inhibit water influx including cement squeezes, polymer, foam or other chemical injection. Unfortunately the success of most of these treatments has been mixed and there has not apparently been a universal treatment which could be applied to the wide spectrum of reservoirs in which the problem is observed.

The Anti-Water Coning Technology (AWACT) is presented as a simple straight forward solution to overcoming the problem of excessive water production due to water coning in oil producing wells. The AWACT process, in its basic application involves the stimulation of a producing well with a natural gas slug and a chemical blend to inhibit the influx of formation water to the wellbore. The effectiveness of this treatment has been successfully demonstrated in the South Jenner field and treatments in other Alberta reservoirs are underway or planned to further refine the process and define its limitations.

AWACT is presented as a solution to the problem of water coning with potential application to range of reservoir characteristics. The AWACT process may be tailored to suit the specifics of most reservoirs. Unlike other remedial methods, which depend upon decreasing water mobility in absolute terms, AWACT relies upon decreasing water mobility in relative terms. Absolute terms are modified individually and hence the permeability is reduced (ie. cement squeezes) or water viscosity is increased (ie. polymers). AWACT affects the relative permeabilities of the reservoir fluids, favouring the movement of oil, not water, to the wellbore.

AWACT treatments have the advantages of being simple, low cost and non-damaging. Routine oilfield practices, equipment and materials are used and a typical treatment time is one week. Natural gas is compressed into the wellhead to chase a slug of chemical blend into the reservoir. Injection rates and volumes tend to be reservoir specific and AOSTRA, through licensing the technology, has taken an active role in the optimization of the process variables.

The results of AWACT treatments in the South Jenner Pool have shown that the process is very cost effective with respect to the production of incremental oil from wells whose high producing water cuts have made the wells candidates for abandonment. The economics have looked favorable enough for AEC to plan to treat 120 wells to improve Suffield oil recovery by 300,000 cubic meters.[1]

Through an active participation program with industry AOSTRA has developed the AWACT process whose large scale application may considerably increase recoverable oil reserves. AOSTRA is currently licensing use of the technology, with technical support, to interested oil producers.

BACKGROUND

Excessive water production due to water coning is not a recently observed phenomenon. However, faced with declining reserves, operators are exploiting more and more oil reservoirs which may be subject to this problem. Most of the currently applied water control methods have been used for less than 25 years and hence the science and art is relatively new.

AWACT was originally patented in 1985[2] and was based upon observations and data analysis from the Suffield Heavy Oil Pilot (SHOP). It was seen that wells within and just offsetting the SHOP in situ combustion project produced considerably less water than the other wells in the field. This could be correlated to the presence of combustion gases.

THE SHOP EXPERIENCE

At the SHOP project (Figure 1), the injection and production wells were perforated only in the oil interval, well above the oil-water interface. The injection and producing wells were initially produced by pumping for a period of 13 months. The produced water cut increased until, on termination of primary production, it was in the order of 40%. After primary pumping, the producing wells were left open and air injection and forward wet combustion was initiated at the injection well. The observation wells, positioned between the injection well and the producing wells, soon indicated that the observable gas movement and temperature increase was taking place mostly along the oil-water interface. Over an extended period, oil was produced, along with combustion gases. This oil was being produced at approximately the same rate as that produced initially during primary pumping. The temperature increase due to combustion was very slow in advancing horizontally through the formation. It appeared that the combustion front was being fed from above by downwardly migrating heated oil. In addition, the rate of water production from the producing wells declined sharply, relative to the rate during primary production, once gaseous communication was established and maintained between the injection well and the producers along the oil-water interface.

Apparently, the combustion process was virtually stalled, with the result that the production wells were basically still on primary production. The oil production rate during this phase was comparable to the original production rate prior to air injection. As well, the water cut was substantially lower, increasing only marginally with time. It appeared that a "gas blanket," evidenced by high gas saturation concentrated at the oil-water interface, was suppressing water coning.

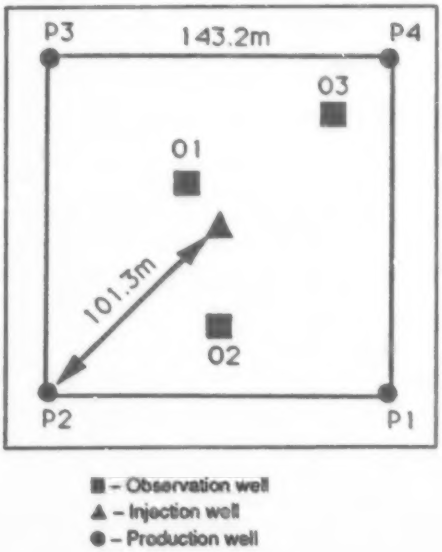

Figure 1. Suffield heavy oil pilot well layout.

RELEVANT LITERATURE

A literature survey was conducted in 1986 to identify published work on the use of gases plus additives to control water coning. At that time, Alikham[3] reported that researchers were investigating methods to inhibit or prevent water coning. These methods included cementing, horizontal fracturing followed by cementing, the use of polymers to reduce water mobility, the use of surface-active agents, and electro-osmosi. Alikham considered these methods to be of "limited efficiency at best" when applied in the field.

The AWACT process was developed around observations made at the SHOP project where water coning, at production wells was reduced during a fireflood. Mobil[4] and Texaco[5] report, for their firefloods in reservoirs with underlying water, similar observations with respect to water production, as those from SHOP.

The use of carbon dioxide in a huff'n'puff mode in reservoirs with underlying water has been reported by Stright[6] and Simpson[7] Results confirm that water coning may be controlled by CO_2 injection in the reservoir.

Further field testing, laboratory evaluations and numerical simulation have been conducted in order to better understand the process sensitivity and optimize the field applications.

HOW AWACT WORKS

Incremental oil recovery from AWACT is attributed to a reduction in the residual oil saturation. This is believed to result from a relative permeability shift which occurs when gas is introduced into porous media containing the oil and water phases. While two phase fluid interactions in porous media have been subjected to extensive study, the explanation of three phase phenomena is less well understood.

In 1970, Schneider and Owens[8] conducted experiments on the effect of gas saturation in waterflood tests. The residual oil saturations decreased with increasing gas saturations. They observed that for both water and oil wet core, the presence of gas caused a significant reduction in water relative permeability. The oil relative permeability was only moderately reduced in water wet rock and gas did not appear to alter the wetting characteristics of the core.

The injection of air for mobility control in waterflooding bottom water reservoirs has been investigated by University of Alberta researchers.[9] It was postulated that air decreased the effective bottom water permeability by the creation of a residual free gas phase. Oil improvement was slight and the concept appears to work best in low permeability reservoirs.

Sayyhouh[10] reported an improvement in oil recovery due to the incorporation of a free gas saturation in the reservoir. He postulated that the reduction in residual oil saturation was caused by interfacial tension effects. Because gas-oil interfacial tension is less than that of gas-water, the fluids may arrange themselves in a minimum energy relationship, whereby the gas molecules enclose themselves within oil globules.

Three phase relative permeability theory implies that both the wetting and non wetting phases will have relative permeabilities which are functions of the saturation. The intermediate wetting phase is subject to interference from the other fluids and its flow capacity will be reduced. In an intermediate wet reservoir one would expect a concurrent reduction in oil and water relative permeabilities with the addition of gas. In oil wet porosities, only the water relative permeability should be reduced.

Other mechanisms which may contribute to the AWACT effect include water displacement by gas, gas drive, oil viscosity reduction and oil swelling.[1]

LABORATORY INVESTIGATIONS

AOSTRA has commissioned a number of laboratory investigations by the Alberta Research Council (ARC) in an effort to better understand the AWACT process. The work by the ARC has included numerical simulation and physical laboratory evaluations.

In AWACT tests conducted by the ARC it was seen that the injection of CO_2, CH_4, and N_2 gases reduced water production in physical sand pack models. Numerical modeling undertaken by the ARC, to match the physical simulator results suggested that the mechanism involved gas migration throughout the oil-water transition zone.

In core flood experiments, restored state cores were alternately or successively flooded with water, gas and oil. The results showed that the water relative permeability decreased following gas injection, residual oil was produced and that a significant critical free gas saturation was established in the core. Additional restored state core floods are currently underway to determine the sensitivity of residual oil reduction to the critical gas saturation and the chemical additives.

Experiments, involving the use of micromodelling techniques,[11] are planned to comprehend the distribution of the fluid phases in porous media and supplement our understanding of the AWACT mechanism.

FIELD TRIALS

Following the SHOP observations, AEC conducted a series of field trials of the AWACT process at South Jenner.[1] Ten wells were cyclically stimulated and the averaged normalized results, shown in Figure 2, predict a 6% increase in oil recovery at a produced water cut off of 96%. The average oil production rate improved from 20 m^3/day to 40 m^3/day.

Variability of the individual well responses was attributed to differences in the sizes of the injected gas slug. Incremental oil recovery and oil production rate appear to be sensitive to the volume of gas injected, the net oil pay and pre-AWACT recovery history. The trade off between incremental oil and gas volumes, in terms of economics, suggests that 50 x 10^3 m^3 was the minimum effective slug size for the South Jenner wells.

The observed response at the SHOP pattern indicated that AWACT could be successfully applied as a flood, where gas introduction into a central injector reduced water production at the offsetting wells. The results of an AWACT pattern flood conducted in the South Jenner pool were unpromising and it was believed that gas fingering overcame the ability of the gas to affect an adequate reservoir area around the production wells.

A pattern was chosen and 900 x 10^3 m^3 of gas was injected into the central well,. To optimize the areal distribution of injected gas, each perimeter well was produced only until the gas production rate reached 3 x 10^3 m^3/day. Once all producers experienced breakthrough, injection was terminated and the shut-in wells were returned to production. Gas was produced for a few days, but none off the wells reacted with the typical AWACT response of instant water reduction. Figure 3 shows a composite of the production response from all of the pattern wells and two adjacent wells which experienced gas breakthrough. Consideration is currently being given to combining the pattern gas flood with AWACT stimulation of the producing wells, for practical applications.

FIELD TRIALS WITH CHEMICAL ADDITIVES

In the early stages of conceptualizing the process

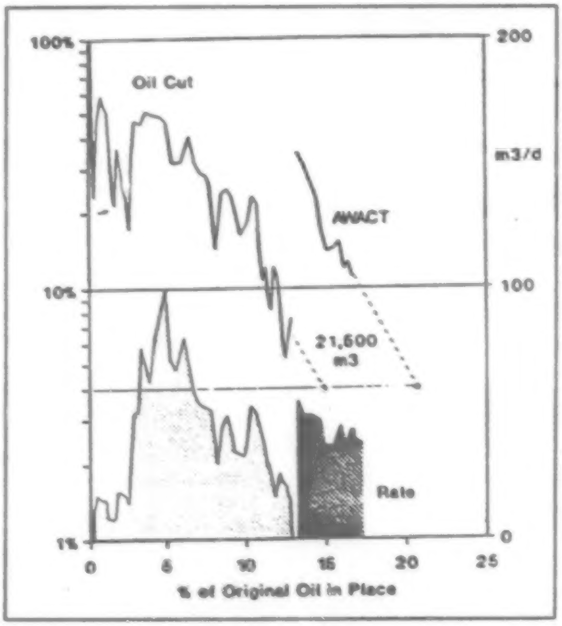

Figure 2. Ten South Jenner AWACT stimulations.

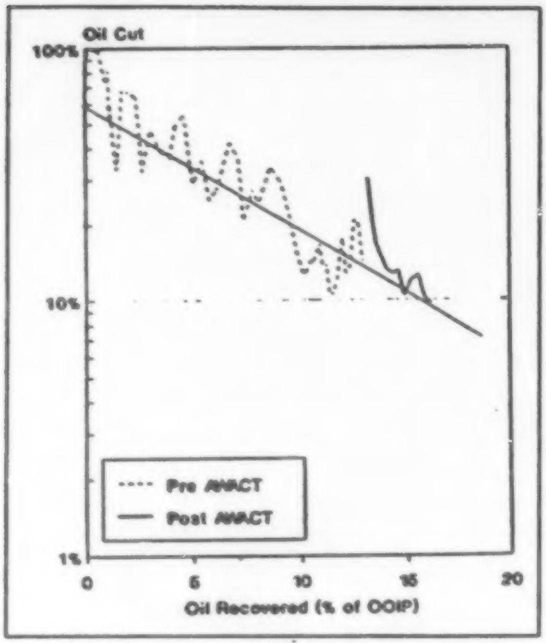

Figure 3. Seven-spot pattern injection.

mechanisms, two theories were developed. The first was that natural gas caused the reservoir to become strongly water wet. This would inhibit water flow by increasing the irreducible water saturation and reducing the water relative permeability. The second theory acknowledged the oil wet tendency of the reservoir and the natural reduction in water relative permeability when a third phase, gas, is introduces in the flow path. To confirm the theories, field tests were modified to pre-inject a chemical which would alter the reservoir to either strongly water wet or strongly oil wet.

Oil wet tests were conducted at two wells. These tests resulted in the most significant increase in oil rate and oil cut from any of the wells previously tested. Injectivity of gas and chemicals into these wells was extremely low and a third test was aborted because neither chemical nor gas could be injected.

Injection of water wetting chemicals at three wells, also resulted in a distinct increase in oil production rate and oil recovery. Unlike the tests using oil wetting chemicals, injectivity was high for all three wells.

These tests of chemical additives did not solve the dilemma of having opposing mechanistic theories; however, it is clear that performance and reliability improved with their use. Research using micromodels and core tests to identify the role chemicals play in the AWACT recovery process are planned.

NUMERICAL SIMULATION

Numerical simulation of the AWACT process has been conducted by the Alberta Research Council, AEC and AOSTRA to better understand the AWACT mechanism and determine some sensitivities to reservoir and process variables.

A numerical modelling study was undertaken by the Alberta Research Council to reinforce the observations, made in 150 cm physical model experiments that the injection of gases suppresses water coning.[12] It was concluded that the main mechanism of water coning suppression appeared to be the gas blanketing or migration along the oil-water contact where the gas mobility is higher. For this reason, the degree of the anti-coning effect should be improved at greater horizontal to vertical permeability ratios. The effect of permeability anisotrophy on relative permeabilities was not studied.

Numerical modelling to history match the results from a South Jenner well, which had undergone an AWACT treatment has been conducted by AEC.[1] The very good post AWACT treatment match shown in Figure 4, was achieved by modifying grid block fluid saturations and relative permeabilities in those blocks where a 1% gas saturation had been introduced by AWACT stimulation. The shift in these values were consistent with measurements made in the previously noted laboratory experiments. Relative permeability shifts due to the presence of the gas phase could then account for the AWACT benefits.

The effect of gas fingering in AWACT stimulated reservoirs has been investigated. The results confirmed that oil recovery can be maximized where there is increased contact between the gas and oil phases. It was shown that this effect can be improved

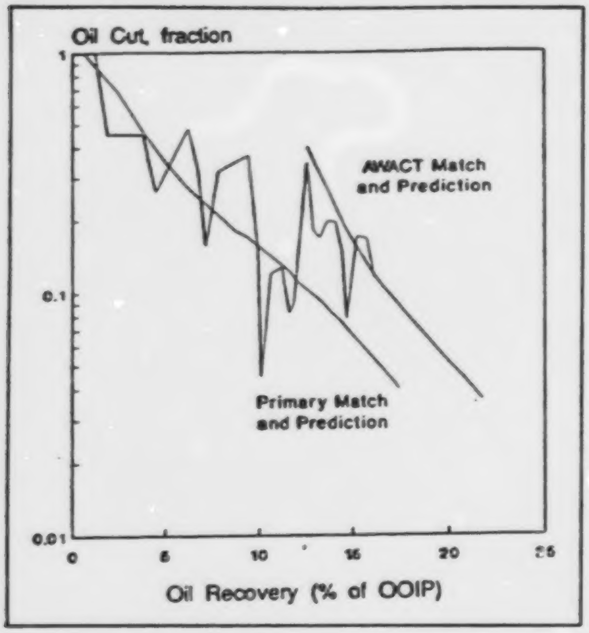

Figure 4. AWACT reservoir simulation.

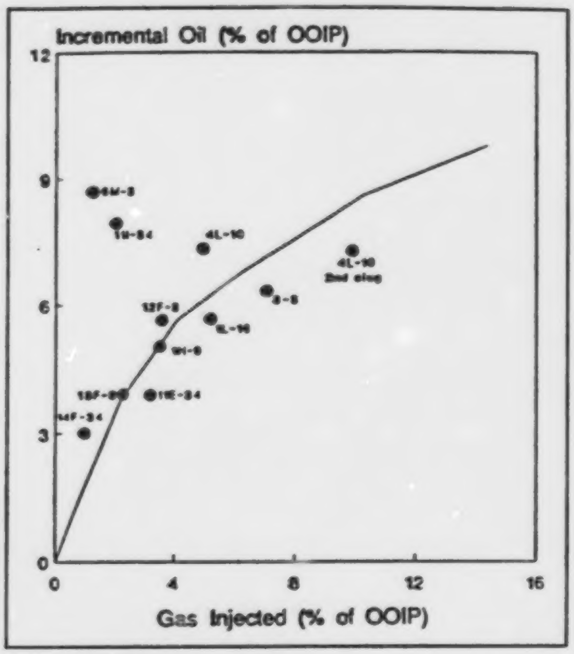

Figure 5. AWACT recovery prediction.

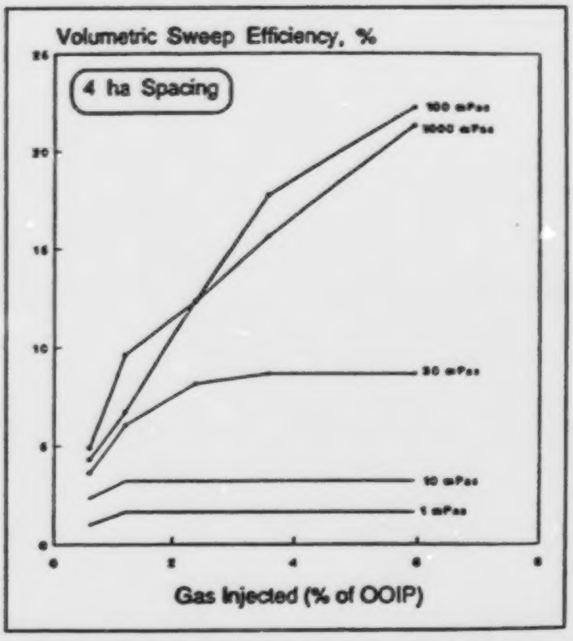

Figure 6. AWACT performance sensitivity to oil viscosity.

by high rate gas injection and is influenced by reservoir anisotrophy.

Figure 5 illustrates the oil recovery predictions from numerical modelling and the actual oil recovery from the South Jenner AWACT simulated wells, based upon the injected gas volumes. There is an apparent correlation between the volume of gas injected and the incremental oil recovery. As expected, larger gas volumes would contact more oil however the tradeoff between increased oil recovery and the time and cost of the larger stimulation has to be determined for individual reservoirs.

Numerical modelling has been used to derive the gas volumetric sweep efficiency as a fraction of the oil zone for various injected gas volumes and oil viscosities. As illustrated in Figure 6 gas will channel to the top of a low oil viscosity reservoir, while in medium oil viscosities, gas will be relatively uniformly distributed across the pay zone, providing the best sweep efficiency. Sweep efficiency is restricted in high oil viscosity cases because the gas migrates along the oil water contact. The inference that AWACT may be most effective in medium viscosity, heavy oil reservoirs is likely mitigated by factors such as relative permeability and the reservoir geology.

It has been shown that the injection of a 500 x 10^3 m^3 slug into an unproduced well gives poor volumetric sweep efficiency compared with that achieved after injection into the well which was produced to a 90% water cut. This observation confirmed that the injected gas will flow more readily into zones having a free water saturation, resulting from water influx or coning.

FIELD PROGRAM

With the success of AWACT treatments in the South Jenner pool, and an understanding of the AWACT mechanisms, AOSTRA has been licensing the use of the technology for field applications. The transfer of technology includes screening of candidates, design of the field program and process considerations and involves a close collaboration between the operators and the AOSTRA technical staff.

The most desirable criteria for the primary application in a candidate pool include: a medium to heavy oil gravity; a net sandstone pay of around 8 meters underlain by water; an absolute permeability of about 1 Darcy; and the absence of an overlying gas cap. The rationale for stipulating these limitations is based upon field experience and numerical simulation predictions.

Natural gas may be sourced from a nearby gas well or a fuel gas line or solution gas from the production battery may be used. Production flowlines can be utilized to deliver low pressure gas to the wellsite, where injection is effected by a portable compressor. The gas injection rate is typically up to 15 x 10^3 m^3/day with limitations on the wellhead pressure to prevent formation fracturing. For injection the bottomhole pump is unseated and the gas is injected via the well annulus. The volume of gas injected has ranged up to 200 x 10^3 m^3. However, a gas volume in the range of 50 to 100 x 10^3 m^3 is now routinely used for AWACT treatments.

Other gases such as CO_2 and N_2, which could be trucked into the site, pumped in a liquid state and vaporized prior to introduction into the well may be used. Compressed air might be another alternative, however the possible risks associated with this practice must be carefully weighted.

The chemical additive blend is comprised of commonly used oil field stimulation chemicals and is available from local suppliers. The premixed proprietary blend is transported in bulk to the well site where a pressure truck or hot oiler is used to inject the chemicals into the well annulus before gas injection.

Following gas injection, the well is shut in and allowed to soak for a period before the well is depressurized by blowing back the gas. Generally less than 25% of the injected gas is recovered (Figure 7).

The bottomhole pump is reseated and a specified initial fluid withdrawal rate is observed to avoid excessive gas production and maximize the AWACT effect. With time the pumping rate can be increased to offset a gradual restoration of the water cut.

OTHER AWACT APPLICATIONS

AWACT has proven effective for water coning

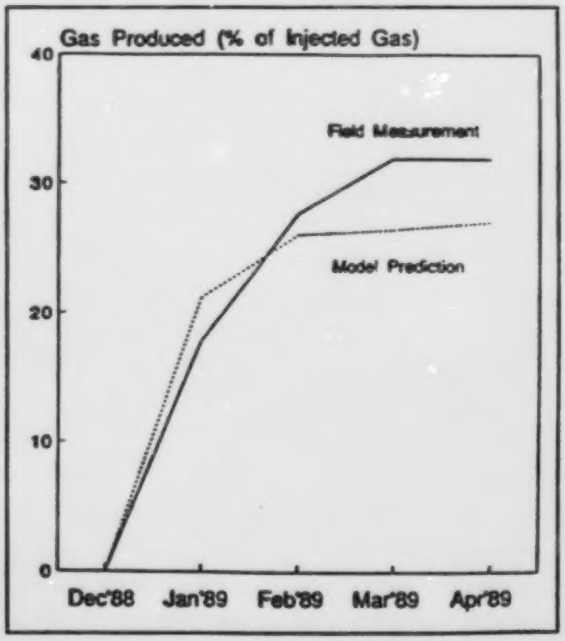

Figure 7. Gas production history match.

control and AOSTRA is exploring other applications to which the technology might be applied. One possibility, which is currently under evaluation with an industry partner, involves the incorporation of the AWACT elements to improve waterflood oil recovery. The results of a numerical simulation study will indicate the feasibility of effectively reducing the waterflood residual oil saturation by the AWACT mechanism.

Since AWACT has the ability to alter the reservoir fluid relative permeabilities, to enhance oil recovery, the application to other reservoir situations is apparent.

For sample, where widespread water influx has increased water saturations throughout an oil zone, to the extent that other remedial methods are impractical, AWACT may provide a feasible option to well abandonment.

CONCLUSIONS

1. AWACT has been proven to increase oil recovery and decrease water production and is available for commercial application.
2. The Alberta Energy Company now considers AWACT to be commercially viable in their South Jenner field for wells producing high volumes of water.
3. The AWACT mechanism involves the introduction of a free gas saturation in the oil to reduce the residual oil saturation. Reduced water production results from three phase relative permeability effects.
4. Field testing has confirmed that the AWACT results are enhanced by chemical additives and their use will be optimized by further laboratory experimentation and field applications.
5. Numerical simulation indicates that gas injection rates, gas volumes, oil viscosity, water saturations and geology are important variables in the success of AWACT.
6. Implementation of AWACT involves routine oilfield practices and can be accomplished in as little as one week.
7. "The record of AWACT pay out and incremental oil recovery justifies its use to raise recoverable reserves.

ACKNOWLEDGEMENTS

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THE FEASIBILITY STUDY OF THERMAL RECOVERY FOR HIGH POUR POINT AND VISCOUS CRUDE OIL

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ABSTRACT

As is known to all, flooding conventional light oil by cold water could achieve high oil recovery, but to recover the heavy crude, thermal recovery methods, such as steam injection and in-situ combustion must be used. However, high pour point viscous oil is different from regular heavy crudes, and the ultimate oil recovery depends greatly on the recovery methods used. In a study of producing high pour point and viscous crude in the Zhaoyuan field, this paper employs reservoir geology, physical models, and numerical simulation to characterize the production of such oil by using different techniques in this field. The results indicate that cold water injection can noticeably decrease the wellbore temperature in injectors, that might create paraffin crystallization from the oil. Such product could plug the formation, reduce water sweep efficiency, and result in a poor oil recovery. Since the recovery of Zhaoyuan crude is strongly sensitive to the operational temperature, thermal recovery processes should be effective for producing this kind of oil. In our studies, the hot water injection processes are emphasized. Production forecasts of cyclic hot water stimulation and hot water slug drive from numerical simulations show that the ultimate oil recovery is greatly increased compared with using cold waterflood. Also presented is a comprehensive economic evaluation of cold waterflooding and thermal recovery processes, the outcome shows better economic beneficial results from thermal recovery methods.

INTRODUCTION

High pour point crude generally has pour points higher than 16°C.[1] In this oil where the paraffin content is high, the pour point is commonly high. It is well-known that there would be serious paraffin deposition problems in the tubing while producing such oil. There are also other possibilities of paraffin crystallization and deposition in the reservoir under certain conditions. For example, when the cold water is injected into the formation and the reservoir temperature is cooled below the cloud point of the oil, the paraffin crystals could develop and plug the pore spaces in the formation. Several studies published in the former USSR investigated this problem, they concluded that cold waterflooding could change the original reservoir conditions and disturb the thermodynamic equilibrium in the formation. Thus, paraffin in the oil would crystallize into solids and become deposits in the reservoir. As a result, this could increase the resistance against oil flow, and decrease water injectivity in some low permeability layers. Consequently, with low injection volume at high mobility ratio between water and oil, the earlier water breakthrough and low volumetrical sweep efficiency deteriorated the ultimate oil recovery.[2,3]

A U.S. patent proposed a three-stage injection process using hot water-cold water-hot water for reservoirs with high pour point oil. The program included: firstly 0.5 PV (pore volume) of hot water be injected into the formation with the temperature 5.6°C to 11.1°C higher than the cloud point of the oil, followed by injecting 0.1 to 0.2 PV of cold water. Then hot water with the temperature same as the first stage should be injected continuously.[3]

The crude oil of Zhaoyuan field in the Dagang region is characterized with high paraffin and high asphalt-resin contents. Its pour point and viscosity are 21–31°C and 95.6–76 mPa·s (the highest is 86 mPa·s at reservoir conditions), respectively. The difficulties of developing this field were the low water injectivity and low oil productivity. In order to overcome such obstacles, this paper presents the investigations of the mentioned problems during cold waterflooding the said reservoir. The feasibility study of thermal recovery processes, such as cyclic hot water stimulation and hot water slug drive, was emphasized for improving oil recovery. Considering the physical properties of the Zhaoyuan crude, the temperature effect of injecting hot water at the different temperatures (from formation temperature to 330°C) in this reservoir was also studied.

RESERVOIR DESCRIPTION AND BRIEF HISTORY OF PRODUCTION

The reservoir of Zhaoyuan field exhibits a faulted nosal structure, which mainly consists of three major fault blocks from the north to south: the Zinaitun, the Zhaobei, and the Zhaonan. Oil production is mainly from Zhao zones member 1 to member 5, which belong to the first section of Kongdian formation (Tertiary) with the average gross and net pays of 96 meters and 32.3 meters, respectively. As previously mentioned, the crude oil is high not only in paraffin and asphalt-resin content, but also in pour point (21°C–36°C) and viscosity (46–86 mPa·s at the formation condition). The average specific gravity of the stock tank oil is 0.909. This field has been on production since 1978 with water injection starting in 1979. In these days, considerable production and injection problems were experienced.

Zhaoyuan field is a faulted reservoir which was cut into many blocks by the flourishing faults. In which, the Zhao 13 fault block was selected as the main target for reservoir geology, physical and numerical model studies. The said block forms a monocline inclining towards the west with a gentle dip less than 10 degrees (Figure 1). The oil sand interval relies upon Zhao II, Zhao III, and Zhao IV zones of the first section of Kongdian, with the main oil reserves in Zhao II. The pay of these sands is generally more than 20 meters with significant phase changes laterally and vertically. Table 1 shows the rock and oil properties in the Zhao 13 reservoir, Which is about 1,700 meters in depth with no edge or bottom water drive. The development of Zhao 13 fault block began in August of 1978. Twelve wells were drilled, including eight producers and four injectors with respectively the estimated average daily production and injection of 12 tonnes and 50 m^3 per well. At the beginning of production, the average daily oil rate reached 17.37 tonnes per well, but declined quickly to 5 tonnes/d a few months later. Cold waterflooding the reservoir was established with the injection

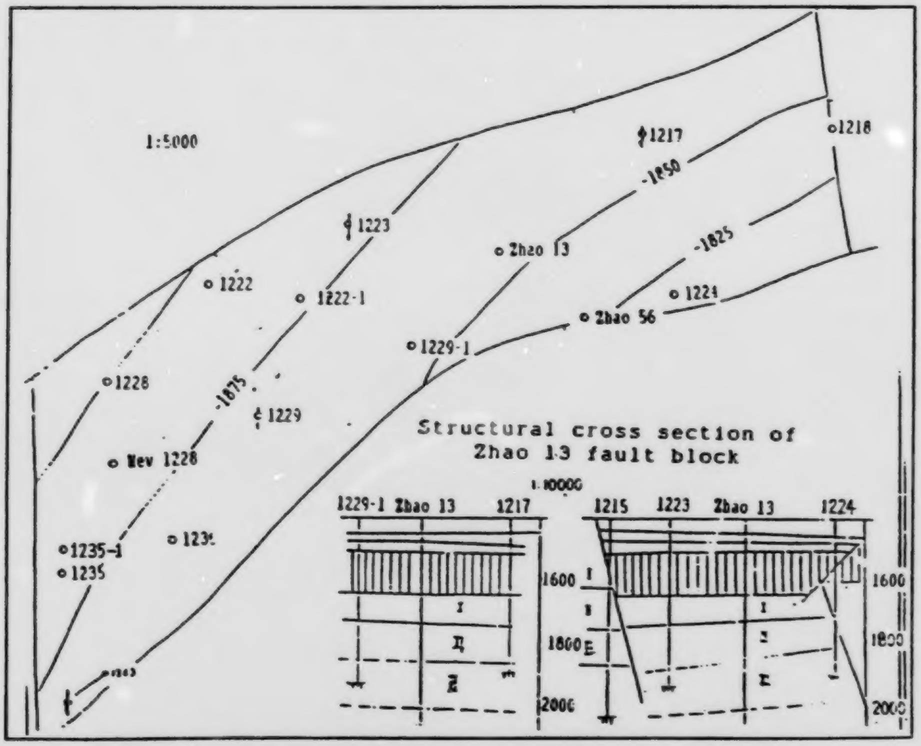

Figure 1. Structural contour map of Zhao 13 fault block and well location.

temperature from 20°C to 30°C, the highest was about 40°C at the well head in July 1979. There were no injectivity problem on most injectors in the early days, but the injection rates decreased rapidly to about 10 m^3/d usually within a few months, and some injectors even failed to take water. By June 1989, the cumulative water injection was 63,600 m^3; most of this was injected into well Zhao 1243. To the same date, the cumulative oil production reached 109,900 tonnes. During this cold waterflood period, the production wells showed very poor responses with no obvious increase of oil production. Most wells had operational problems with heavy loads at the pumping equipment and with frequent sucker rod breakdown. As a result, the oil producing rate was low, mostly at about 3 to 5 tonnes/d. To be brief, this waterflood operation was disappointing, since the injection could not balance the reservoir voidage and supply the energy for oil displacement. Therefore in order to improve water injectivity, many technical measures were taken, such as pulsing injection, surfactant solution for reducing oil viscosity, reservoir fracturing and acidizing, etc. However, nothing has been significantly achieved.

Table 1. Reservoir parameters and fluid properties for Zhao 13 Fault Block

Depth of reservoir, meter	1736–2036
Effective thickness of oil formation, meter	12.6–36.6
Initial reservoir pressure, Mpa	18.65
Initial reservoir temperature, °C	75
Saturation pressure, Mpa	3.63
Porosity, %	23–24
Permeability, md	400–500
Initial oil saturation, %	65
Specific gravity of oil at stock tank condition	0.8831–0.9524
Oil viscosity at reservoir condition, MPa·s	86.02
Paraffin content %	19.16
Asphalt-resin content, %	24.08
Pourpoint of crude oil, °C	23–33
Cloud point of crude oil, °C	55
Melting point of paraffin, °C	68
Initial ratio of gas to oil, m^3/ton	12.5

PHYSICAL SIMULATION STUDY

Analysis of the Crude Oil Components and the Gas Chromatogram of the Crude Oil

From the analysis of the Zhaobei oil is exhibited: paraffin content – 20.31%; asphalt-resin content – 17.82%; and pour point temperature – 23°C. Further analysis by using gas chromatography was done. The distribution of alkanes in this oil is presented in Table 2 in which, the hydrocarbons are scattered with peaks between C_{28} and C_{33}. According to the published literatures, these are the main contributors to forming paraffin crystals from crude oils. That is the reason of easy paraffin crystallization in the Zhaobei oil.

Table 2. Gas chromotography showing the distribution of alkanes of Zhaobei Oil

Component	Weight, %	Component	Weight, %	Component	Weight, %
C_5	2.45	C_{17}	4.19	C_{29}	4.07
C_6	0.28	C_{18}	2.46	C_{30}	5.86
C_7	0.55	C_{19}	1.69	C_{31}	5.40
C_8	2.02	C_{20}	1.23	C_{32}	5.54
C_9	3.77	C_{21}	1.17	C_{33}	1.76
C_{10}	5.17	C_{22}	1.06	C_{34}	2.08
C_{11}	5.09	C_{23}	0.94	C_{35}	0.64
C_{12}	5.82	C_{24}	0.82	C_{36}	0.51
C_{13}	8.29	C_{25}	0.59	C_{37}	0.20
C_{14}	6.86	C_{26}	0.65	C_{38}	0.19
C_{15}	7.09	C_{27}	0.97	C_{39}	0.19
C_{16}	6.31	C_{28}	1.87	C_{40}	0.56

The Viscosity-Temperature Correlation of Zhaobei Oil

The relationship between viscosity and temperature for Zhaobei oil was determined as displayed in Figure 2, which shows that the dead oil viscosity at reservoir temperature is 480 mPa·s. According to the Standard for Heavy Oil Classification in China, the crude with viscosity greater than 100 mPa·s at reservoir condition should be classified as a heavy oil. Therefore the Zhaobei crude — a heavy oil with high paraffin content and high pour point — should be considered as a candidate for thermal oil recovery.

Figure 2 shows that the viscosity temperature relationship of the Zhaobei oil is characterized in three-section lines with different slopes at ASTM coordinate paper. The shéar rate related viscosity at low temperatures is a distinctive property of a high pour point crude. Thus, the Zhaobei crude is a high pour point oil as well. The intersects of three lines correspond separately to the critical temperature and the cloud point, which are respectively 36°C and 55°C for the said crude. When the oil is cooled below the critical point, its viscosity behaves like a non-Newtonian fluid and is related with both temperature and shear rate. If the oil temperature is higher than the critical point, the oil viscosity is only the function of temperature. But in the region between the critical temperature and the cloud point, or above the latter, the difference in the lines' slopes indicates that the oil viscosity would be significantly affected by the forming of paraffin crystals. As shown in Figure 3, the melting point of paraffin in the Zhaobei oil is 68°C, so paraffin crystals could be created when the formation is cooled below the cloud point (55°C). Thus higher reservoirs temperature greater than 68°C are required to melt the paraffin crystals for effective oil production.

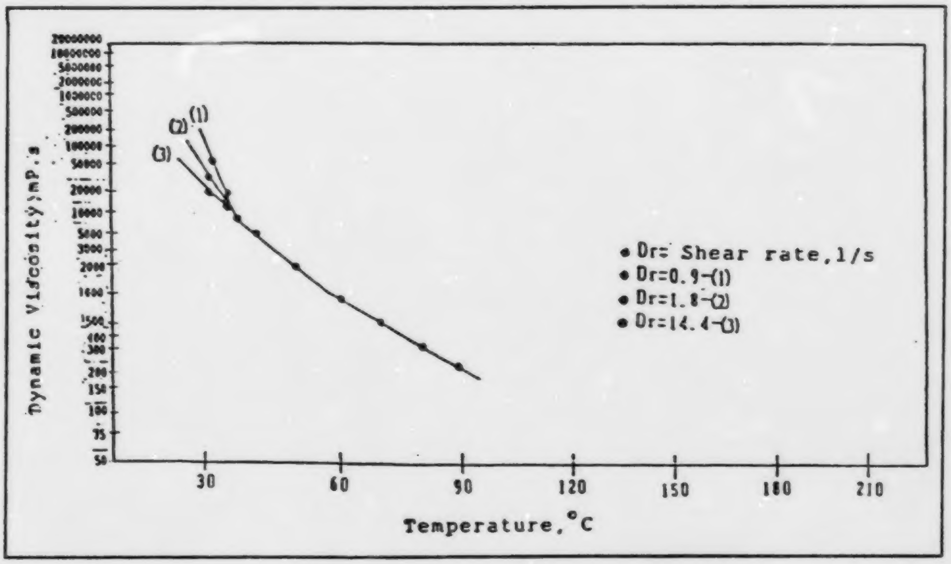

Figure 2. Viscosity-temperature correlation for Zhaobei oil.

The Effect of Temperature on the Oil Permeability

High temperature relative permeability equipment was used to measure the oil permeabilities for this study. As shown in Figures 3 and 9, the oil permeability declined as the temperature was lowered, and rose again with increasing temperature; but the changes did not take the same routes. Figure 3 shows that below a temperature of 54°C, the measured oil permeability decreased due to paraffin crystallization. Thus if the operational temperature in this field is below 54°C, the solidified paraffin crystals could plug the pore spaces and lead to permanent damage to the formation.

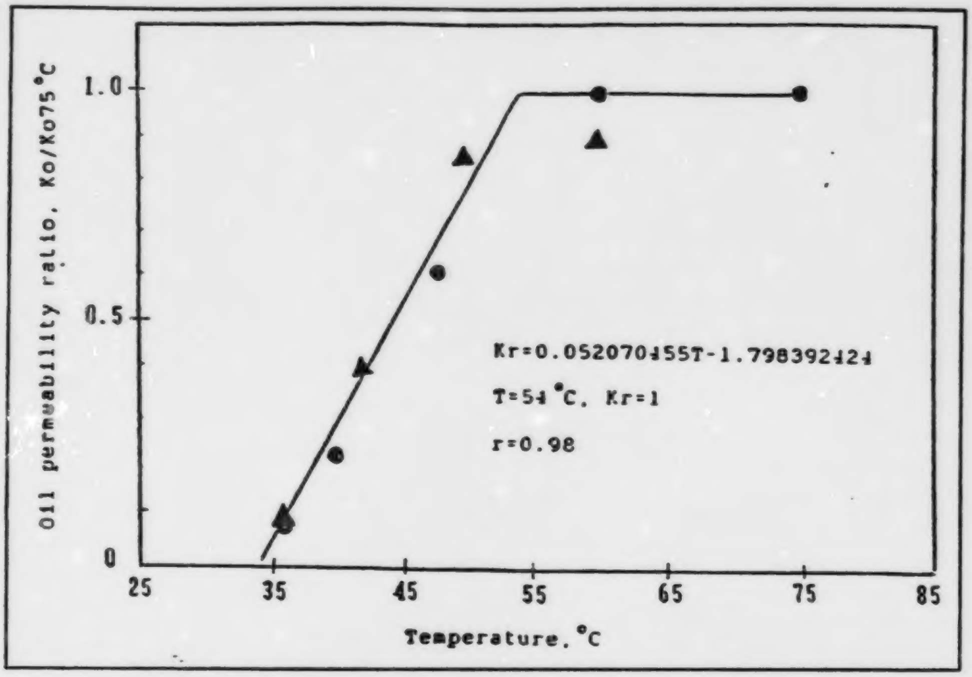

Figure 3. Relationship between oil permeability ratio and temperature.

The Effect of Injected Water Temperature on Waterflood Sweep Efficiency

From the special core studies, the changes of residual oil saturation by waterflood at different temperatures were measured. The results shown in Table 4 indicate that the residual oil saturation in the cores is much higher in tests with low temperatures (S_{or} of 47% by waterflood at 95°C) and dropped rapidly when the injected water temperature increased. Figure 5 shows the changes of sweep efficiency calculated based on the initial oil saturation of 65% at the different flooding temperatures. Evidently, the sweep efficiency can be greatly enhanced by increasing the temperature in the injected water.

DESCRIPTION OF NUMERICAL MODEL AND SIMULATION OF RESERVOIR TEMPERATURE PROFILE

Description of Reservoir Numerical Model and History Match to Field Production

A three-dimensional, multiphase, multicomponent simulator was utilized for simulation of thermal recovery processes in the Zhaoyuan field. The studies included the modeling of reservoir temperature profile after cold water injection, of hot water stimulation, and hot water slug drive. The model describes mass transport by Darcy flow, incorporating gravity, viscous, and capillary forces. The heat transport includes the mechanisms of convection and conduction within the reservoir and conductive heat loss to the overburden and underlying strata. This model can simulate the oil recovery processes of primary production, conventional waterflood, cyclic steam or hot water stimulation, hot waterflooding, steam drive, in-situ combustion, etc.

In order to establish the basic parameters for numerical simulation, firstly, the history match of water injection in well Zhao 1293 and oil production from well Zhao 1236 over a period of eight years was completed before the further studies. In the phase of history match, the grid system with 9*9*7 blocks shown in Figure 6 and the geological parameters listed in Table 5 were adapted in the said model. The matching curves are presented in Figures 7 and 8.

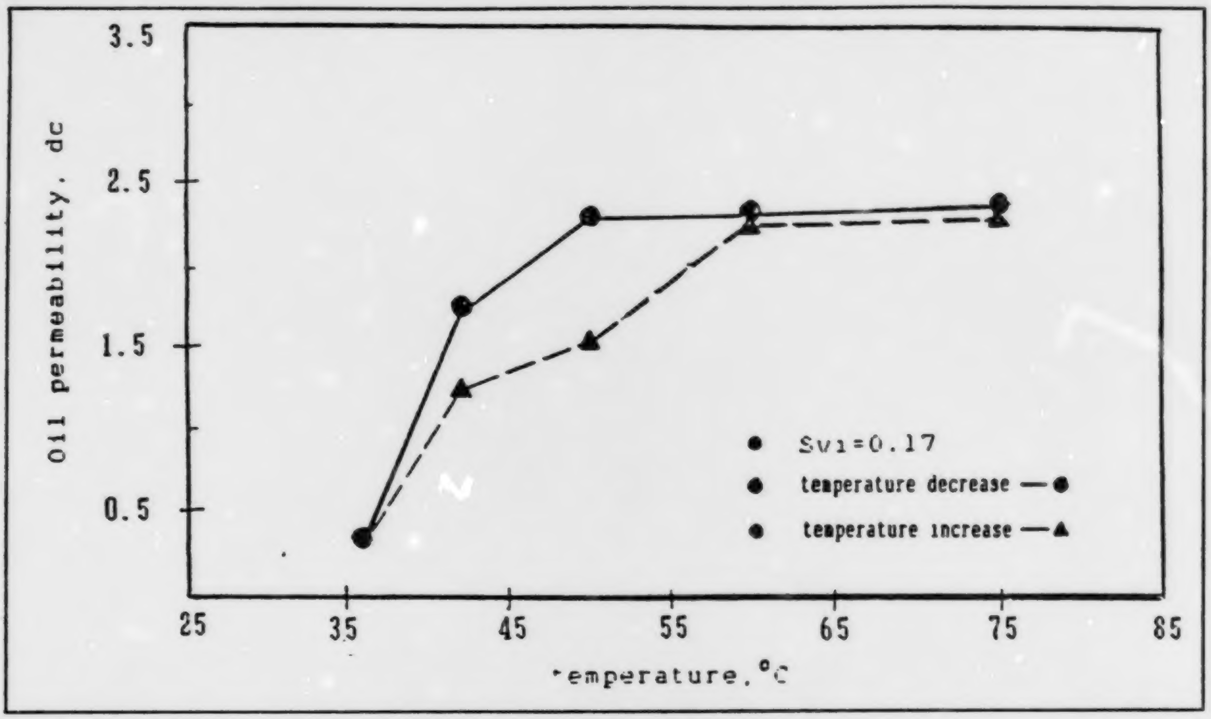

Figure 4. Curves of oil permeability versus temperature with irreducible water existing.

Table 3. Experiment data for the melting point of paraffin and cloud point of crude oil

Temperature, °C	Saturation Pressure, MPa	Cloud Point, °C	Melting Point, °C
70–74	0	55	68

Table 4. The relationship of fluid saturation and temperature by waterflooding and steamflooding

Temperature °C	Irreducible water saturation, Swi	Initial oil saturation, Soi	Residual oil saturation, Sor
45	0.211	0.789	0.467
60	0.244	0.756	0.303
75	0.288	0.712	0.268
120	0.356	0.644	0.160
160	0.369	0.631	0.140
200	0.521	0.479	0.095
200°C steam	0.554	0.446	0.083

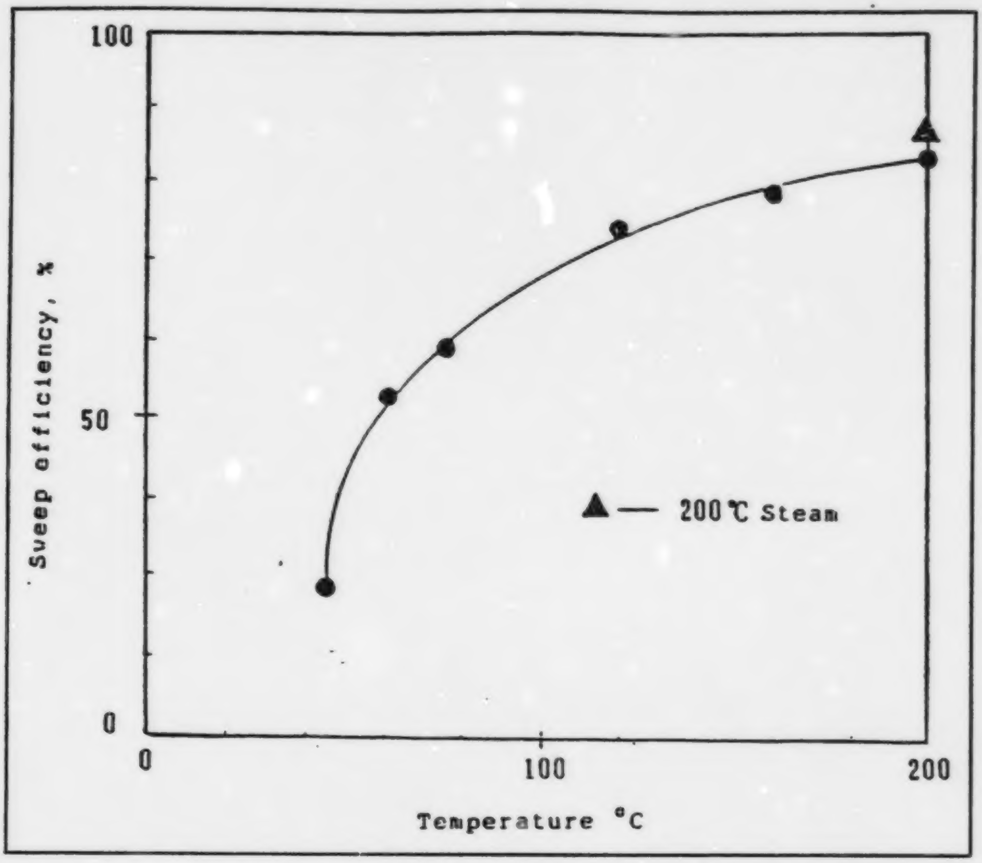

Figure 5. Sweep efficiency curve from different temperature waterflooding and steamflooding.

The Effect of Cold Water Injection on the Temperature Profile of Formation Around the Injector

Simulation of wellbore temperature indicated that the injected water temperature at the bottomhole will be 40°C to 45°C, while the wellhead injection is 25°C to 30°C at the rate of 100 m^3/d to 120 m^3/d.[7] Thus, the wellbore injection temperature of 40°C was chosen in the numerical model. This simulation focuses on the changes of temperature profile of formation around the injector with three injection rates; namely 50 tonnes/d, 100 tonnes/d, and 150 tonnes/d. The geological aspect was simplified in the model with only two permeable layers, one with high permeability, the other with low permeability. The temperature distribution in the high permeability layer between an injector and a producer are shown in Figure 9 (injection) and in Figure 10 (shut in), also Table 7 presents the forecast results. It can be seen that the initial formation temperature (75°C) would be reduced especially in the area around the injector due to cold water injection, and the cold front would intrude gradually into the reservoir with time prolonging. The temperature at certain areas around the injector is even less than the cloud point (55°C) of the oil. This would lead the formation of paraffin crystals, that could plug up the reservoir. During later shut-in of the injector, the temperature of the cooled bank would be raised again by the natural geothermal energy, but cannot be recovered to the original reservoir temperature (68°C) even after a long period (one year) of shutting-in the injection well. In this situation depending upon well shut-in, the existing paraffin crystals would not be melted totally. For instance, at an injection rate of 100 tons per day, the temperature of the formation 0.5 m from the injector is 43.7°C after eight days of water injection. Also the region with temperatures below 55°C (eight days injection) is the area within 2 m of the injector. After 24 days of water injection, however, the region extends within the formation 5 m from the injector. Regarding the temperature recovery in a case of one year injector shut-in after one year water injection, the formation 3 m from the

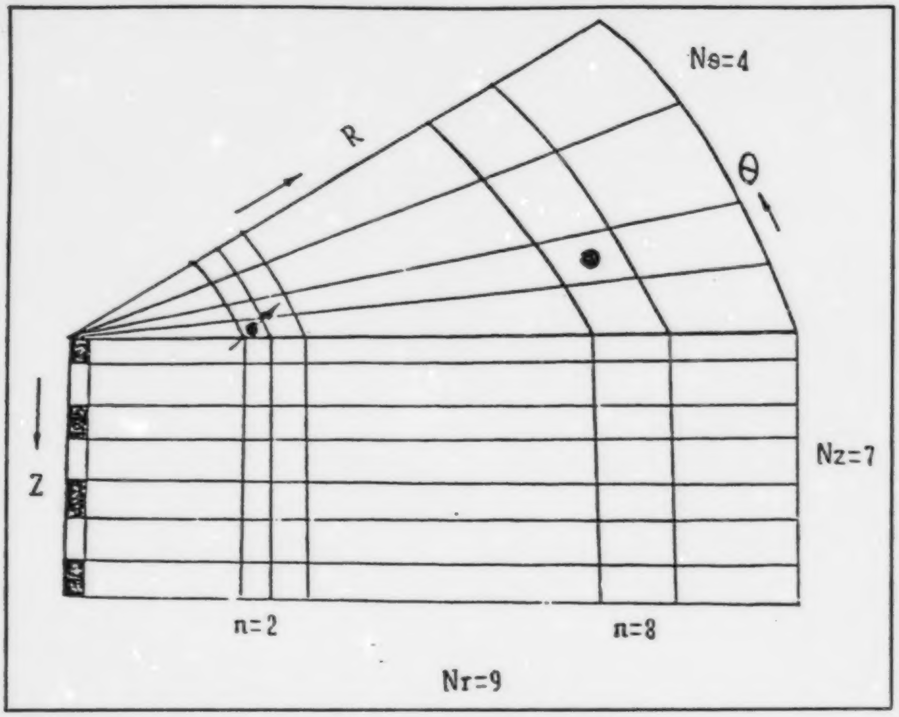

Figure 6. Grid system used in history match.

Table 5. Geological model for history match

	Thickness meter	Porosity %	Permeability md	Oil saturation %
Sandstone	4.4	24.2	513.8	53.8
Shale	10.8	/	/	/
Sandstone	7.9	24.3	717.4	67.1
Shale	11	/	/	/
Sandstone	2.3	24.9	1272.9	60.2
Shale	6.9	/	/	/
Sandstone	4.9	21.6	159.6	60

injector would recover its temperature to 58.2°C. This is still below the melting point of the paraffin crystals, which simply cannot be melted away in the oil.

PREDICTION OF PRODUCTION PERFORMANCE OF CYCLIC HOT WATER STIMULATION AND HOT-WATER SLUDGE DRIVE

Cyclic Hot Water or Steam Stimulation

The single well model was used for the numerical simulations of cyclic hot water stimulation (CHWS) and of cyclic steam stimulation (CSS). The input parameters were gross thickness of producing interval of 52.6 m, effective thickness of 18.15 m, the net/gross thickness ratio of 0.345 and oil viscosity of 87 mPa·s at reservoir condition (75°C). Since the thermal recovery processes would be carried out on the existing wells with drainage radius of 150 m and on the future close-spaced pattern wells with drainage radius of 75 m. For both cases, the CHWS and CSS processes were simulated for seven cycles. In such operations, the total cycle injection volume was increased by 20% for each latter cycle to ensure that the increasing injected heat would be enough for propagating heating zone and for enhancing production. The results from simulations indicate that, as long as the technology of preventing heat loss meets the demand for the existing well, noticeable effectiveness can be achieved from CHWS. The average oil rate for a producer can

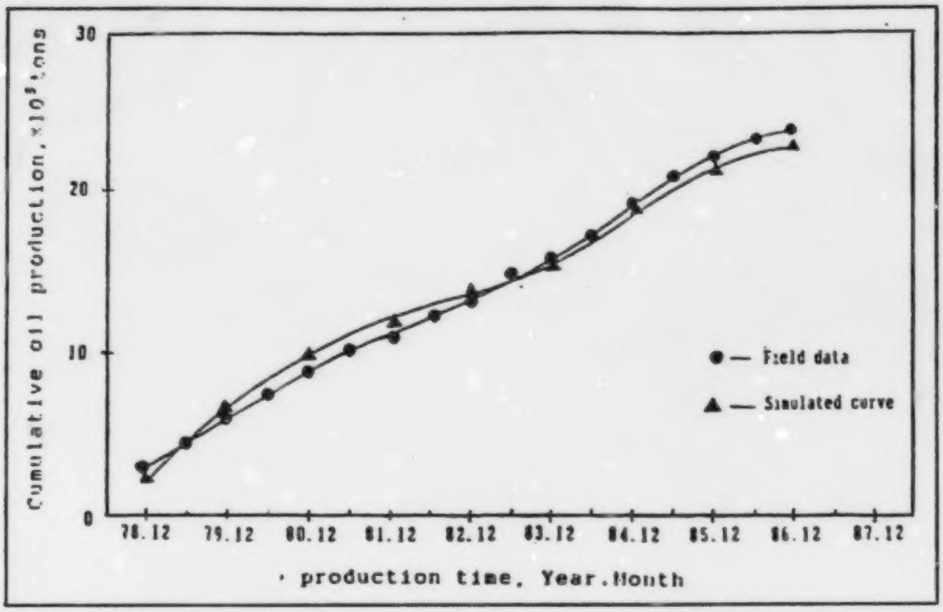

Figure 7. History match curve of cumulative oil production.

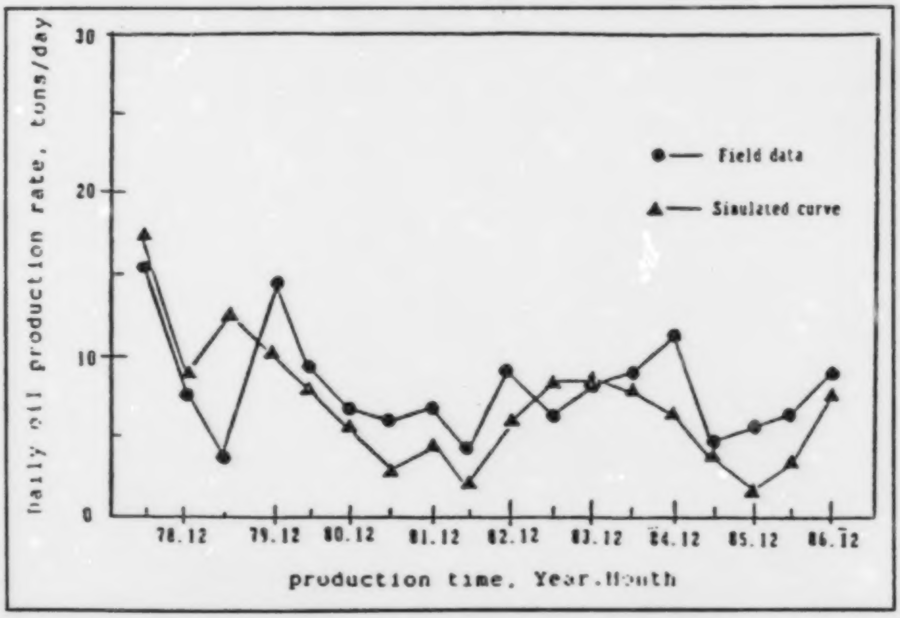

Figure 8. History match curve of daily oil production rate.

be promoted to more than 10 tonnes per day, if the bottom hole temperature in the water injector is maintained higher than 200°C. For the new well, the oil producing rate can be greatly lifted by CHWS or CSS. The cyclic stimulation by using 330°C steam with quality of 20% would double the oil rate from the conventional production. Table 7 summarizes the detailed results.

Hot Water Slug Drive

Numerical simulation was conducted to study the production performance of hot water slug drive (HWSD) with the four-spot well network shown in Figure 12. This pattern will be formed after the infill wells are drilled. Actually the said pattern could also be termed as an inverted seven-spot well network, with the distance of 150 m between injector and producer. The Grid system in the model is shown in Figure 13. Twelve cases of recovery operation were simulated, such as:

(a) Cold waterflood.

(b) Cold waterflood after hot-water (330°C) stimulation for three cycles in the injector, while the producer was on production or shut-in.

(c) Cold waterflood after 0.2 PV, 0.4 PV, 0.6 PV of hot water slug (330°C) drive.

(d) Case C after hot-water stimulation for three

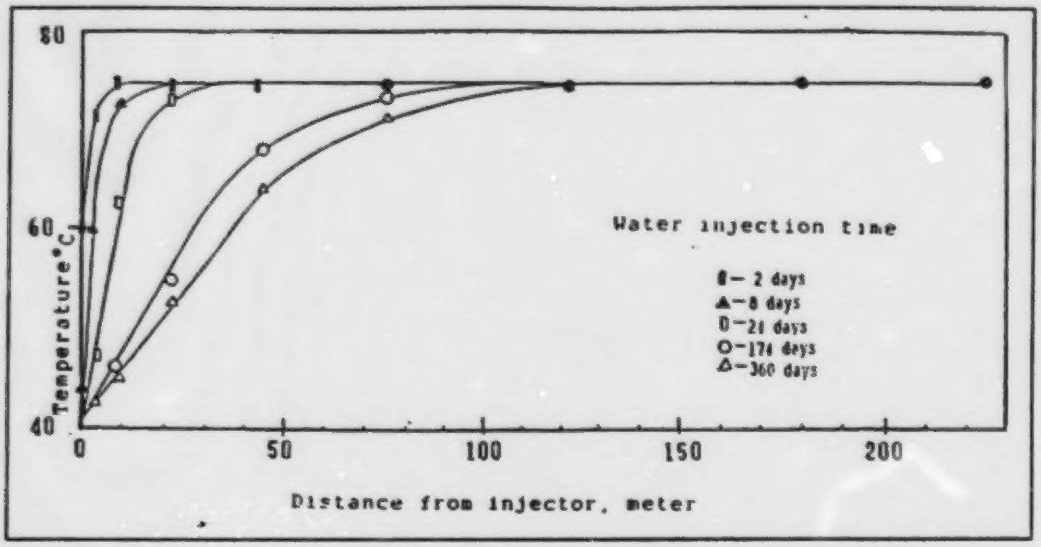

Figure 9. Reservoir temperature profile after cold water injection (injection rate 100 tons/day).

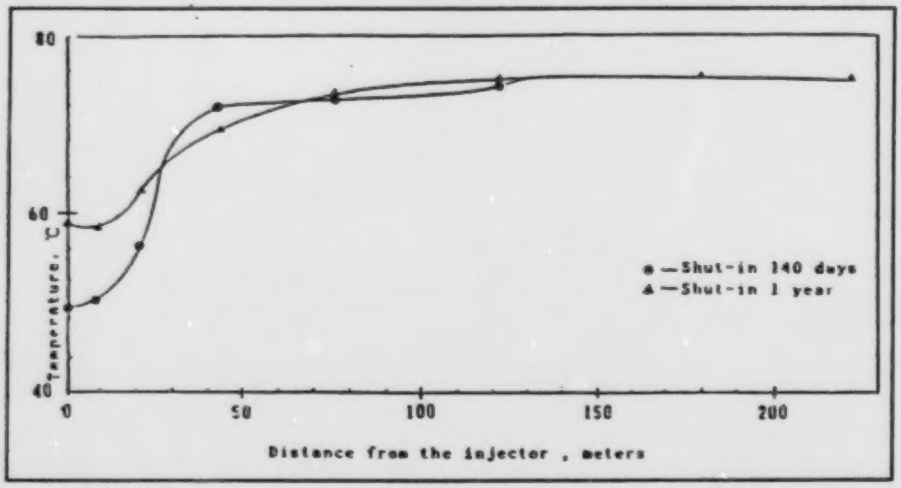

Figure 10. Reservoir temperature profile after one year of cold water injection (injection rate 100 tons/day) following injector shut-in.

cycles, while the producer was on production or shut-in.

Table 8 lists the simulation results of several cases including a cold waterflood and seven thermal operations. Accordingly, it is concluded:

1. No matter which thermal process is employed, the ultimate oil recovery (UOR) would be much better than that from cold waterflooding (50°C). The UOR of the latter is less than 23% of OIP. From this, the incremental oil recovery of HWSD is about 10%. The net oil (gross increase subtracts fuel use) production is more than 4,000 tonnes produced from a single well group. In general, the net incremental oil from the said thermal operations is greater than 5% of OIP (the highest could be 6.75% OIP).

Table 6. Status of temperature decrease of the formation around injector after cold water (40°C) injection

	Ran of tem Dec. meter	Ran of tem <55°C meter	Ran of tem <68°C meter	Tem 0.5 m fr Inj. °C	Tem 3 m fr Inj. °C	Tem 10 m fr Inj. °C
In jection rate, 50 tons/day						
Injection time, day						
3.7	3	/	/	58.8	73.1	75
23	15	3	/	45	57.6	70.7
360	100	20	/	42.6	44.2	47.7
Shut-in time, day						
7	100	20	43	45.4	45.1	48.5
141	75	7	20	56	54.7	56.8
360	43	3	20	60.4	50.7	60.6
Injection rate, 100 tons/day						
Injection time, day						
2.4	3	0.5	/	55.3	72.2	75
24	23	6	/	41.6	47.4	62.1
360	110	26	/	40.8	42.2	45.2
Shut-in time, day						
7	110	26	70	43.2	43.1	45.9
141	75	8	40	54.3	52.8	54
360	75	/	50	59.4	58.2	58.5
Injection rate, 150 tons/day						
Injection time, day						
2.8	5	1	/	49.2	69.4	75
29	28	7	/	41.5	46.2	59.5
360	110	25	/	40.8	42.2	45.2
Shut-in time, day						
7	110	25	55	43.2	43.1	45.9
140	75	9	45	54.3	52.8	54
360	75	/	40	59.4	58.2	58.5

Table 7. Prediction results of seven cycles hot water or steam stimulation

In water temp, °C	Cum Inj tons	Cum prod oil, tons	Prod time days	Avg. daily prod., tons	Cumul. OWR	Net cum oil, tons
Old well						
200	22400	9050	868	10.43	0.404	7951
250	22400	9220	863	10.68	0.412	8055
300	22400	9410	819	11.49	0.420	8173
New well						
Cold prod	/	2960	548	5.40	/	/
300	22400	7380	534	13.82	0.329	6135
300	22400	7530	539	13.97	0.336	6130
300°C steam	22400	7770	534	14.55	0.347	6170

Note: 300°C steam with quality 20%

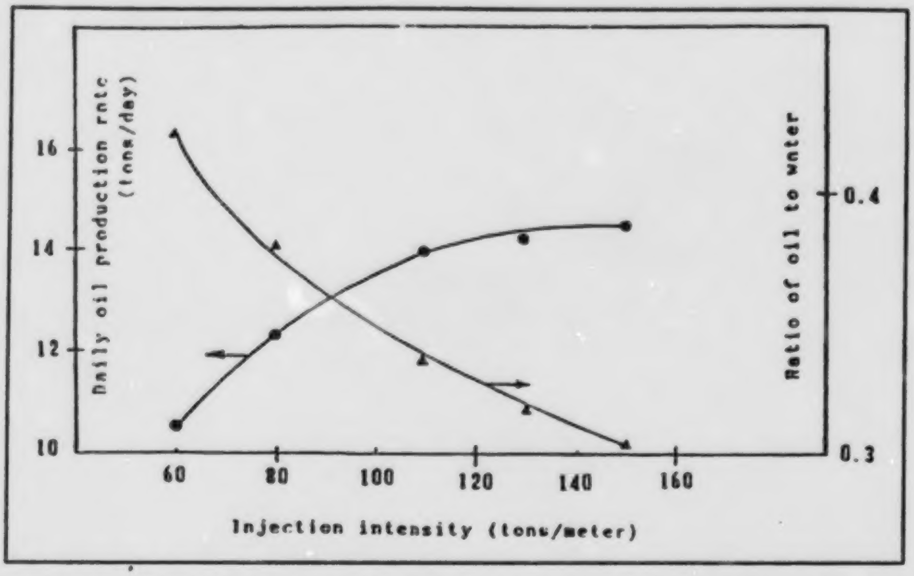

Figure 11. Plot of daily oil production rate and oil-water ratio against injection intensity of 330°C CHWS.

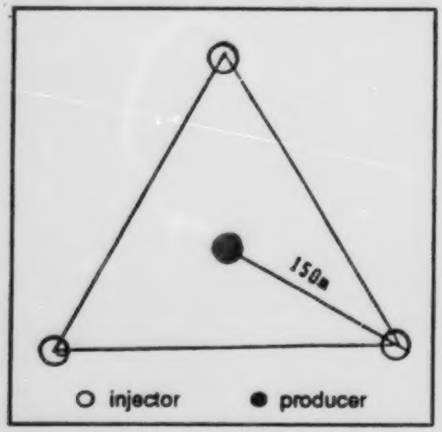

Figure 12. Well pattern shape used in the simulation of hot water slug drive.

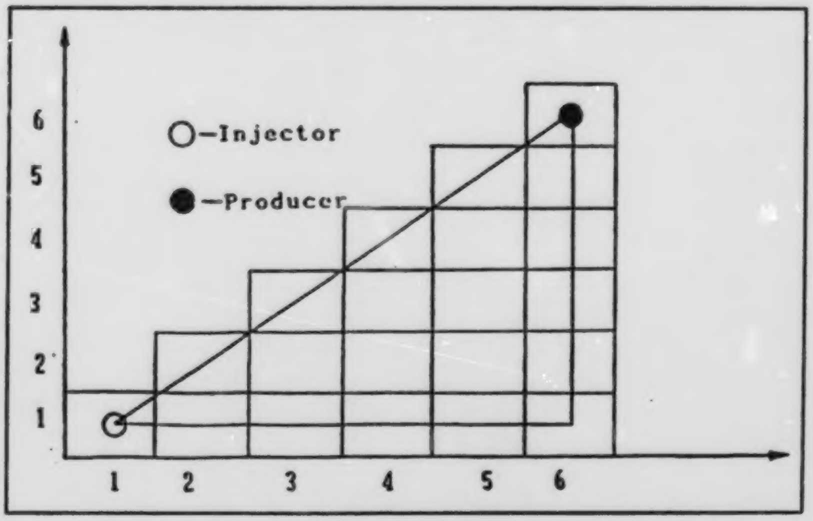

Figure 13. Grid system used in the simulation of hot water slug drive.

2. The production performance of HWSD following cold waterflood is slightly better than CHWS following cold waterflood. The net incremental oil recovery is more than 6% OIP and 5.5% OIP for the former and latter respectively.
3. The size of hot water slug has minor effects on the ultimate oil recovery of HWSDs, but the preferable slug size ranges from 0.2 PV to 0.4 PV.
4. The timing of starting HWSD in simulations slightly affects the overall production performance. However, in considering the low injectivity of injectors at Zhaoyuan Oilfield, the program of CHWS for two or three cycles following HWSD would be preferable. Since the CHWS would clean the wellbore and its surroundings also would increase water saturation in that area for easier injection in HWSD.

Table 8. Comparison of recovery effectiveness of thermal recovery programs

Recovery programs	Prod time day	Cum oil prod, tons	Cum water prod, tons	UOR %	Cum inj hot water tons	Fuel oil tons	Net cum oil prod, tons	N.I.R. %
CFW	2324	14,690	41,110	23.19	/	/	14,690	1
CHWS + CWF 0.2 PV HWSD	2294	18,410	108,660	29.06	3600	225	18,185	5.52
+CWF 0.4 PV HWSD	2268	19,940	116,000	31.48	21,600	1350	18,590	6.2
+CWF 0.6 PV HWSD	2530	21,400	130,340	33.79	43,200	2700	18,700	6.3
+CWF CHWS + 0.2 PV HWSD	2790	22,530	144,780	35.57	64,800	4050	18,480	6.0
+CWF CHWS + 0.4 PV HWSD	2509	20,540	120,630	32.43	25,200	1575	18,990	6.75
+CWF 0.4 PV HWSD	2660	21,770	128,630	34.36	46,800	2925	18,845	6.56
+CWF CHWS + 0.4 PV HWSD + CWF	2928	22,860	143,430	36.09	68,400	4275	18,585	6.15

Notes:
1. N.I.R. refers to net increased oil recovery, CWF to cold waterflooding, CHWS to cyclic hot water stimulation and HWSD to hot water slug drive.
2. CHWS at injector with three cycles and with producer on conventional production.
3. Fuel oil is calculated based on 16 tons hot water (330°C) generated by burning one ton oil.

5. Based on the results among the programs, three cycles of hot water stimulation, then 0.2 PV HWSD following cold water flooding is the best approach to improve oil production. This case resulted in a highest net incremental oil recovery of 6.76% OIP. Moreover, considering the reasons described in (4), this program is thought to be optimal and its production forecast from the simulation will be the foundation of following economic evaluation.

The effect of injected water temperature of HWSD on UOR was investigated. Figure 14 shows the curves of UOR and the status of cumulative oil production (SCOP) versus injected water temperature. The marks corresponding to 330°C shows the results of case (d) with 0.4 PV injection for HWSD. The other points show the results of only 0.4 PV for HWSD following cold waterflood without CHWA. It can be seen easily that UOR would be considerably promoted with the increase of injection temperature. So the HWDS at 330°C resulted in a high UOR increase in our studies. In addition, the recovery process of using high temperature CHWS-HWSD-cold waterflood can greatly improve the SCOP in a short period, which is evidently shown in Figure 14. On the other hand, the operation temperature does affect the selection of field equipment for thermal recovery. However, the difference in investment and operating costs for the high and low temperature operation is not that much. The overall heat loss in the wellbores of deep wells (more than 1,700 meters) is certainly significant. Therefore, speaking on the whole, high temperature HWSD is preferred to the recovery of high pour and viscous crude oil in this field.

As an additional note, although the Zhao 13 fault block reservoir is deeply buried, the demand of injecting high temperature (330°C) water at bottom hole can be achieved by adapting the advanced heat insulation techniques and well completion programs. For example, drilling new injectors with 7" casings, which are pre-stressed for completion, and putting insulated tubing down the hole filled with special liquid in the annular space. The simulation of well bore heat losses from the injectors with such completion indicated that the injection temperatures

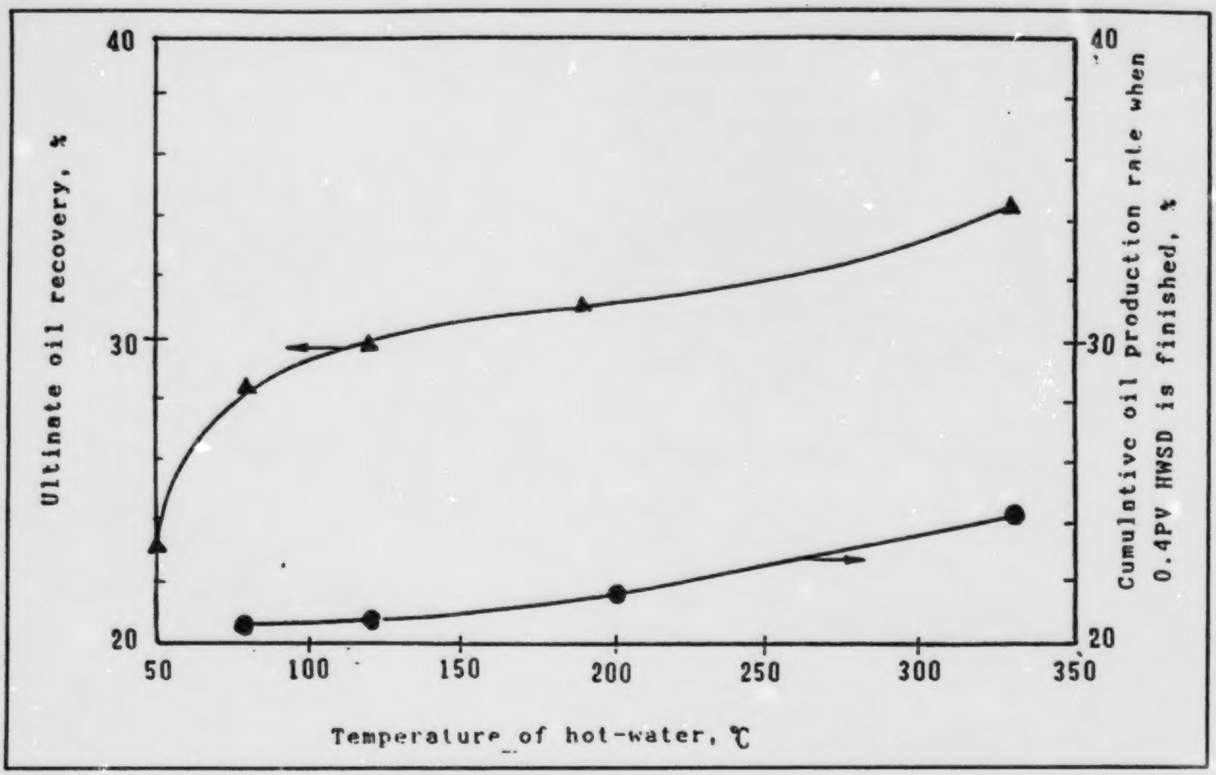

Figure 14. Plot of ultimate oil recovery and cumulative oil production rate against temperature of hot water injected in HWSD.

at wellbore could reach more than 330°C for hot water or for 330°C steam with quality 30 to 70% at a rate between 100 to 140 m^3/d.[7]

ECONOMIC EVALUATION

An economic evaluation of thermal recovery was conducted based on the results of physical and numerical simulation discussed earlier. The study firstly evolves predictions of annual production and injection in a pilot operation (4-spot pattern) and enlarged scale (20-well group). For the pilot test, total production period of cold waterflood and of HWSD are estimated to be seven and nine years with cumulative oil production of 63,600 and 99,600 tonnes, respectively. For the enlarged scale, total production period of cold waterflood and of HWSD are estimated to be 11 and 13 years with cumulative oil production of 439,400 and 642,900 tonnes, respectively. Using the economic indexes developed by the Institute of Geology Research, Dagang Petroleum Administration Bureau, and referring to such information used for other heavy oil development in China, the comprehensive economic evaluation for cold production and thermal recovery processes was performed by using four economic evaluation criteria, which are discounted rate of return, payout period, net present value, and cost of oil. The results listed in Table 9 indicate that although the investment and operating cost of thermal recovery processes are higher than that of cold production, the overall benefit, however, is much better than that of primary recovery.

Moreover, the thermal recovery operation would produce about more than one half oil of cold production. To sum up, the chief objectives of developing Zhaoyuan field are to increase the oil well productivity and to accelerate field development. The discussed thermal recovery processes certainly help to reach this purpose.

Table 9. Economic evaluation results

	4 well groups		20 well groups	
	Cold waterflooding	Thermal recovery	Cold waterflooding	Thermal recovery
Discounted rate of return %	15.0	14.4	29.7	26.4
Payout period, year	3.8	3.7	3.6	4.4
Net present value, 1000 years				
Discount rate, %				
0.0	4022	7564	90,829	131,681
5.0	2295	4187	62,214	85,076
10.0	996	1683	41,515	53,013
15.0	6	–198	26,279	30,495
20.0	–756	–1627	14,897	14,404
Cost of oil, yuans/ton				
0.0	416.8	404.1	273.3	275.2
5.0	439.1	431.3	304.7	310.3
10.0	460.1	456.6	338.0	347.8
15.0	479.9	482.9	372.7	387.0
20.0	498.4	507.2	408.5	427.4

CONCLUSIONS

1. Based on the high pour point and high oil viscosity, the Zhaoyuan crude is a special heavy oil. The oil recovery by cold waterflood is poor and thermal recovery processes are the valid technical measures to improve the recovery efficiency for this kind of oil.
2. The cloud point of Zhaobei crude oil is from 36°C to 55°C, and the melting point of paraffin is 68°C. A characteristic of three deflected lines occurs at the curve of viscosity-temperature with two intersects from these lines, which separately correspond to 36°C and 55°C. The first one is the critical point, at which, the crude begins to behave like a non-Newtonian fluid with the appearance of paraffin crystals in it. The second one seems to be the cloud point of the oil, which indicates that the paraffin crystals start to form in the crude. The experiments on oil permeability shows that if the temperature of oil formation is decreased below 54°C, the paraffin crystals out of the oil would plug up the formation and result in formation damage.
3. The reservoir temperature can be decreased by cold water injection, which could lead paraffin crystallization within an area of about 5 m from the injector. Once the low temperature zone exists, it is hard to get it back to the original temperature even after a long period of well shut-in. Thus, the permanent formation damage is the main reason to cause low injectivities for cold water in this field.
4. The ultimate oil recovery is about 23% OIP from the cold waterflood. The average oil rate per well is between 4 to 6 tonnes per day. But, if the cyclic high temperature water stimulation (CHWS) is used, the daily oil production rate per well can be enhanced to 9–10 tonnes with doubled oil recovery (Table 7).

5. The optimal case of thermal recovery processes is the operation using CHWS to purge the formation contamination, then apply HWSD, and finally to flood the reservoir with cold water. The estimated oil recovery of this approach would be 10% above that of cold waterflood. After the fuel oil is deducted, the net increased oil can reach to more than 6% of OIP. For thermal recovery in a 4-spot pattern with distance of 150 m between producer and injector, two or three cycles are preferred for the hot water stimulation. Regarding the size of steam slug, 0.2 PV to 0.4 PV is the best selection for HWSD.
6. Hot water slug drive process can considerably increase the oil recovery for the high pour and viscous crude oil. Although the investment and operating cost are much higher compared with cold waterflood, the overall economic beneficial results are better with much more cumulative oil production and higher net present value in profit. In general, the better economic results are from the larger thermal recovery project. The cost of oil for commercial thermal recovery process is estimated at about 380 yuans per tonne.

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Reservoir Engineering Study of Steam Injection into Shallow Heavy Oil Reservoir, Northwestern Margin of Junggar Basin

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RIPED, Xinjiang Petroleum Administration

ABSTRACT

A reservoir engineering study is a cornerstone of successful steam injection for heavy oil recovery. In recent years, many countries have developed their own techniques, and their use has already made great contributions to the development of their heavy oil steam injection recovery.

This paper presents the study of reservoir parameters for decision making, and the development of operational strategies for heavy oil recoveries in the Junggar Basin. Based on the experience obtained from steam injection in the Karamay field, this article details the classification of heavy oil, screening criteria for steam injection, recovery techniques, well spacing and flood pattern, and optimization of the injection parameters for steam injection to recover heavy oil. Moreover, the future efforts of the reservoir engineering studies are discussed.

INTRODUCTION

In the last 20 years, heavy oil thermal recovery techniques and field tests have been widely developed and conducted around the world. At present, the steam injection recovery technology attains maturity, and the reservoir engineering studies certainly played important roles for this success.

The development of heavy oil reserves by steam injection requires the studies of classification of heavy oil reservoirs, screening criteria for recovery process selection, operational sequences, well spacing and flood pattern determination, optimization of injection parameters, and production performance prediction.

In the recent years, there was rapid progress on Steam injection and evaluation for heavy oil recovery in the Karamay field. With great efforts, the production scale was expanded, oil rates were increased, and some technical problems were solved. Also, research and studies on heavy oil reservoirs have been improved. Based on this, we can certainly handle the design and field management for large-scale steam injection projects in the future.

CLASSIFICATION OF HEAVY OIL AND SCREENING CRITERIA FOR STEAM INJECTION PROCESSES

Different opinions in these regards were published. However, considering geological characteristics and fluid properties in the northwestern margin of the Junggar Basin, the studies from the Institute of Exploration and Development, Xinjiang Petroleum Administration (IED) indicated that the heavy oil classification standard (Table 1) recommended by W.Z. Liu of RIPED, Beijing, is suitable for heavy oil reservoirs in the mentioned basin.

Table 1. Classification criteria of heavy oil by Mr. Liu (China)

Classification	Viscosity	Density	Recovery technique
heavy oil	50–100	<0.92	waterflood
	100–10,000	>0.92	thermal
extra heavy oil	10,000–50,000	>0.95	thermal
super heavy oil (natural bitumen)	> 50,000	>0.98	thermal

Screening Criteria for Steam Stimulation Processes

Based on the data related to oil recovery in the Karamay field including production and steam stimulation from about 1,000 wells, numerical simulations, steam injection laboratory tests, and the relevant economic evaluation in other oil fields, the screening criteria for steam stimulation processes were then determined. The parameters selection depend upon the sensitivity and influence to heavy oil recovery. These involve oil viscosity, net pay, reservoir factor (net to gross pay ratio), porosity, oil saturation, and oil content per unit volume (the product of porosity and oil saturation).

In view of the oil price changes (middle and high), the critical state of these parameters was decided by using net present value (NPV) from the economic evaluations, along with the oil recovery and economic benefits. In addition, the rapid improvement of recovery technology could also affect the development economics. Thus, the present, improved, and future technical levels were included as important factors to make the use of this screening criteria (Table 2) more widely.

Screening Criteria for Steamdrive Processes

In general, steamdrive is conducted after a short period of steam stimulation in the heavy oil reservoir. The conversion from stimulation to flooding depends on the conditions of reservoir geology, heating zones by steam stimulation, and pressure declines. Although the steamdrive consumes more steam than that of the steam stimulation process, but the former could achieve higher sweep efficiency and oil recovery.

The driving mechanism of a steam flood process is much more complex than that of steam stimulation and waterflood. And the petrophysical and reservoir fluid properties affect the thermal operation and oil recovery obviously. These parameters therefore should be studied for steamdrive process. Most of the published screening criteria were available for both steam stimulation and steamdrive processes. However, Table 3 shows the criteria for steamdrive processes recommended by IED. Since we only have limited experience in steamdrive tests in the Karamay oil field, this standard was prepared based on the data obtained from literatures and from our files. The lower limits of these parameters in Table 3 remain further confirmed.

In viewing these parameters, the most influential factors for steamdrive process are oil viscosity and net pay in the reservoir. Thus, a heavy oil pool, with dead oil viscosity less than 10,000 mPa·s and with net pay over 10 meters, could be a candidate for steamdrive.

Table 3. Screening criteria for steamflooding process

Parameter	Value
Oil viscosity (mPa·s)	<10,000
Net thickness (m)	>10
Net/pay	>0.5
Porosity	>0.20
Oil saturation	>0.45
F • Soi	>0.12
Permeability	>500
Depth (m)	150–600

Table 2. Screening criteria for steam stimulation process

Technique	Oil price	Viscosity	Density	h	Net/pay	Soi	F	F • Soi	D
percent	mid.	100–10,000	0.937	>5	>0.5	>0.60	>0.28	>0.18	<350
	high	100–20,000	0.937	>5	>0.5	>0.50	>0.25	>0.15	<600
improved	mid	10,000–20,000	<0.94	>5	>0.5	>0.55	>0.25	>0.15	<600
	high	10,000–50,000	<0.95	>5	>0.5	>0.45	>0.23	>0.13	<600
future	mid.	20,000–50,000	<0.95	>5	>0.4	>0.45	>0.20	>0.13	<1600
	high	>50,000	<0.95	>5	>0.4	>0.40	>0.20	>0.13	<1600

On the other hand, steam stimulation should be applied in the heavy oil reservoirs with dead oil viscosity of more than 10,000 mPa·s or with net pay ranging from 5 to 10 meters.

HEAVY OIL RESERVOIR STEAM INJECTION STRATEGY DESIGN

Reservoir Description and Geology Model

Heavy oil reservoir description should be emphasized in the following aspects:

(a) *Tectonics.* It mainly describes the influences of tectonic regime, and the fracture system on the distribution of oil, gas, and water in reservoirs.

(b) *Oil reservoir.* It should be described emphatically for statistical analysis of oil-bearing zone lithology, cement contents and components of cementation grade, changes of the reservoir rocks on the horizon and profile, interbed thickness and distribution, sedimentary facies, clay minerals and water sensitivity, as well as reservoir heterogeneity.

(c) *Rock pore space.* It mainly describes reservoir pore size, distribution, and possible changes during steam injection.

(d) *Reservoir fluids.* It describes the distribution of reservoir fluids, their physical properties, and especially the changes of oil viscosity during steam injection.

(e) *Relative permeability.* It chiefly describes the oil-water, oil-gas relative permeabilities at high temperatures, steam displacement efficiency, and rock sensitivity to hot water.

(f) *Reservoir pressure and temperature.* It predominantly describes reservoir pressure and its distribution, formation breakdown pressure, and reservoir temperature.

Following the detailed reservoir description, a three dimensional reservoir model should be utilized for further studies. From which, the optimal recovery techniques, recovery sequences, well spacing and patterns, and operational parameters would be selected for future practice in order to maximize oil recovery and economic benefits.

Recovery Sequences Selection

In recent years, field practice and research studies indicate that recovery sequences selection for steam injection should follow these principles:

(a) At a given flood pattern, the same recovery sequence should have certain net pay in the reservoir in order to gain higher economic benefits.

(b) Reservoir factors in recovery sequences should meet the requirement of screening criteria for steam injection process, in most cases, perforation intervals should be less than 40 meters.

(c) Lithological, rock, and oil properties in the same sequences should be basically uniform, especially that difference between oil viscosities is not allowed to be excessive.

Recovery Techniques Selection

The techniques required to recover heavy oil include conventional waterflood, in-situ combustion, steam stimulation, and steam flooding

The waterflood process is suitable for heavy oil reservoirs with oil viscosity of less than 100 mPa·s. However, its recovery efficiency is often less than 15% of OOIP due to waterflooding reserve utilization factor of less than 0.5, waterflooding utilization index of less than 0.1 (Figures 1 and 2). Hot water injection would not increase the reservoir temperature significantly, because of less heat carried by hot water and wellbore heat losses. Thus, it is unfavorable to recover such heavy oil with viscosity exceeding 100 mPa·s in the reservoir.

Theoretically, the in-situ combustion process has the following advantages:

1. higher energy utilization;
2. lack of produced water disposal;
3. negligible water sources and wellbore heat losses, etc.

Undoubtedly, it provides a valid means to recover heavy oil from deeper formations. But, this process is very complicated in field operation and control, and the risk is high. At present, only a few in-situ combustion field tests are successfully applied in the

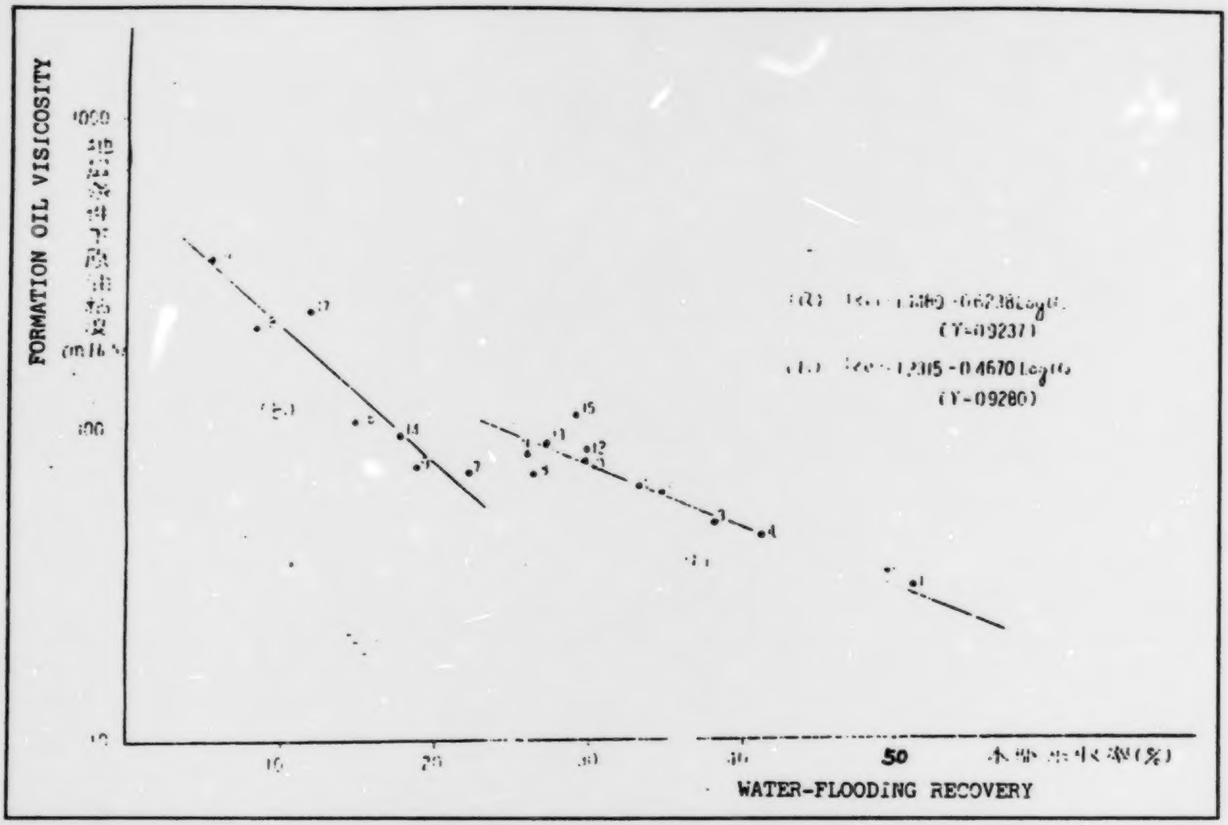

Figure 1. Waterflooding recovery-formation oil viscosity relation.

heavy oil reservoirs in the world. Further research, studies, and pilot tests need to be done to improve this technique.

Steam stimulation is one of the most effective techniques to recover conventional heavy crude and can be widely used in various kinds of heavy oil reservoirs. Many field tests were performed indicating that the use of this method led to a technically and economically lower risk and a pronounced production increase. Our steam stimulation screening criteria for shallow heavy oil reservoirs could be successfully applied for those with dead oil viscosity of 20,000 mPa·s at reservoir temperature, net pay of greater than 5 m, reservoir factor of higher than 0.5, porosity of more than 25%, and oil saturation of greater than 50%. The results of our field tests indicate that accumulated oil-steam ratio was over 0.5, and oil recovery higher than 25%.

It should be mentioned the said limit of oil viscosity can be extended to 50,000 mPa·s, because of the recent improvement of field technologies, such as high pressure injection, wellbore oil viscosity reduction, oil pumping and gathering transmission techniques. For example in Canada, steam stimulation bas been applied in the tar sands reservoirs with oil viscosity ranging from 50,000 to 100,000 mPa·s. For this operation, Imperial Oil utilized a well spacing of 1.62 hectares in the Cold Lake pools, Alberta, where injected steam volume reached 10% of pore space, and the oil recovery exceeded 20%. According to our experience to recover such super heavy oil, a steam stimulation test was conducted in a pool in District 9(8) with dead oil viscosity over 100,000 mPa·s. The total oil production in the first cycle reached 1,485 tonnes and oil-steam ratio was 0.676. In addition, similar tests have also

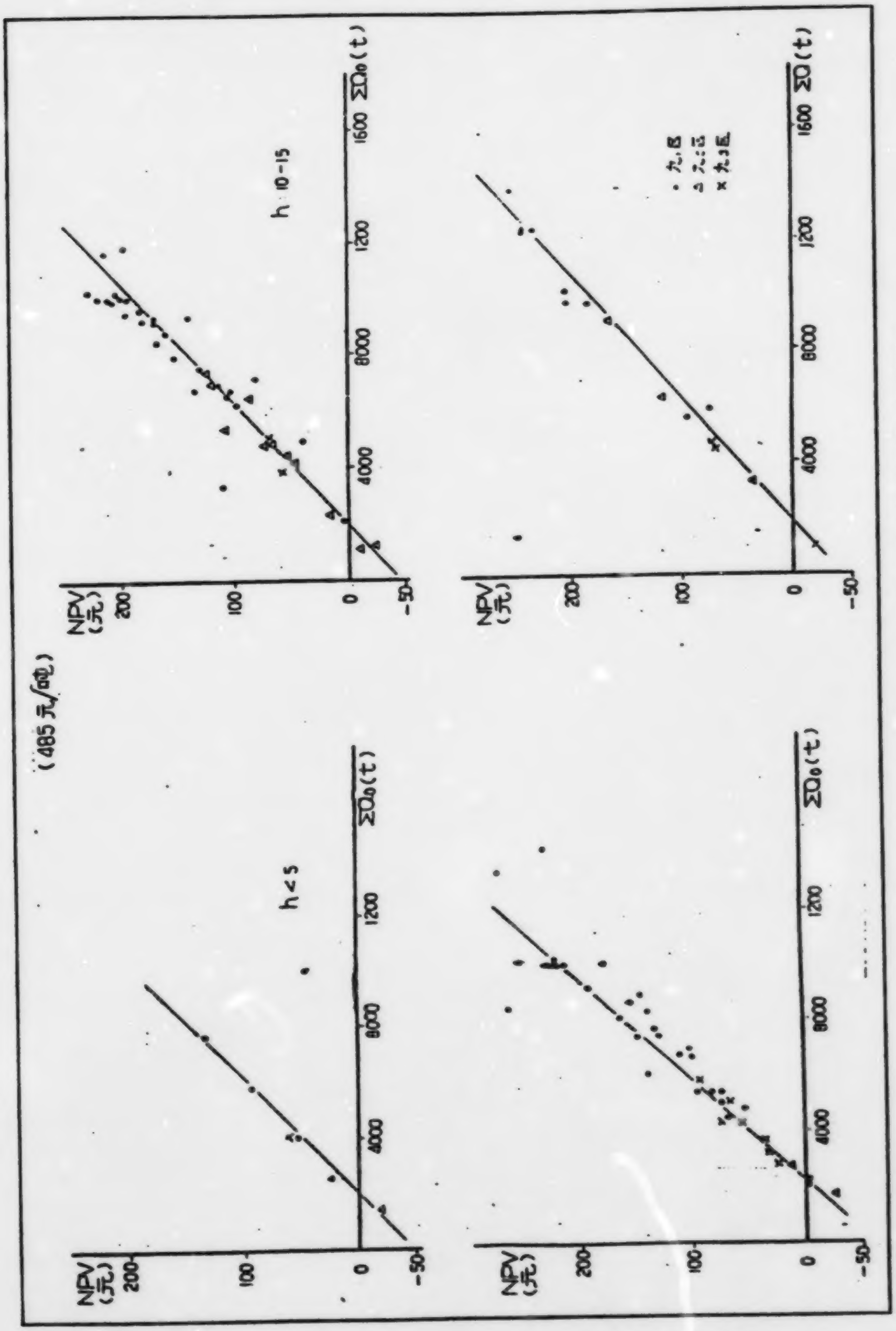

Figure 2. Net percent value (NPV) – cumulative oil production (SQo) relation.

been conducted in the reservoirs with oil viscosity ranging from 500,000 to 1,000,000 mPa·s in the Wind City area. The results were satisfactory.

The driving mechanism of the steamflood process is more complex. In addition to the water displacement, it has other effects, such as the reduction of oil viscosity and residual oil saturation as well as steam distillation. Because of high oil viscosity and poor mobility in the reservoirs, the initial oil recovery by steamdrive must be low. Thus, by using steam stimulation at the beginning, when heat communication is formed between injection and production wells, the stimulation project could then be converted to steamdrive. In this case, better oil recovery can be obtained due to its higher displacement efficiency and viscosity reduction. As described above, steamdrive recovery mechanisms are very complicated. The oil recovery depends not only on the geological conditions but also on field operation, such as the timing of the project conversion from stimulation to steamdrive. The suitable geological conditions for steamdrive have been described in Table 3. However the following are the influences of stimulation on steamdrive:

(a) During steam stimulation, excessive injection pressure could result in an early steam breakthrough and well interference. It is unfavourable for steamdrive recovery.

(b) During steam stimulation, the erratic horizontal pressure drop would affect steamdrive recovery efficiency.

(c) At the beginning of the steamdrive, the oil saturation should be greater than 0.45 to 0.5 to ensure higher oil mobility for steam flood.

(d) During steam stimulation, heat communication between the injectors and producers, the basic requirement for steamdrive, should be formed as early as possible.

(e) During the steamdrive, steam quality in most cases must be more than 70% or over 60% for deeper wells, thus sufficient energy supplied by steam can heat the reservoir to obtain good results.

Well Spacing and Flood Pattern Selection

The widely-used methods for heavy oil thermal recovery are steam stimulation and the steamdrive process. Because of slight differences between their mechanisms, the selection of well spacing and flood pattern are not the same.

Flood pattern has minor influence on oil recovery by steam stimulation due to injection and production in the same well. Well spacing is selected based on the heating radius which can be estimated by using heating area calculations or by numerical simulations. Currently, there are several kinds of heating area calculation methods, among which, the calculation formula recommended by Marx and Langenheim is popularly used. For this approach, the irregularity of the heating area should be considered, and that must be corrected by area sweep efficiency. Numerical simulation method is that where the heating radius is calculated by mapping the relationship between reservoir temperatures and the distance from the wellbore (Figures 3 and 4), these were simulated under different geological conditions and different operation strategies.

For development of District 9(6) in Karamay field, the calculations from these two methods were almost the same. That is for steam stimulating a reservoir with net pay of 10–20 m and dead oil viscosity of 10,000–50 000 mPa·s at 20°C, well spacing should be 60-80 m, and well control area be 6,400–10,000 m^2. For thicker reservoirs, well spacing should be reduced; on the contrary, well spacing must be increased accordingly.

As mentioned above, for a scheme conversion from steam stimulation to steamdrive, the oil viscosity should be less than 10,000 mPa·s. After three to six cycles of stimulation, the project is converted to steamdrive, in this case, flood pattern can be selected principally depending upon oil viscosity. Because low injectivity normally occurred in the reservoirs with viscous oil, flood patterns with a smaller producers to injectors ratio should be chosen to balance the volume of injection and production. For reservoirs with relatively low oil viscosity, the flood pattern with higher ratio of producers to injectors such as inverted seven-spot or nine-spot pattern should be selected.

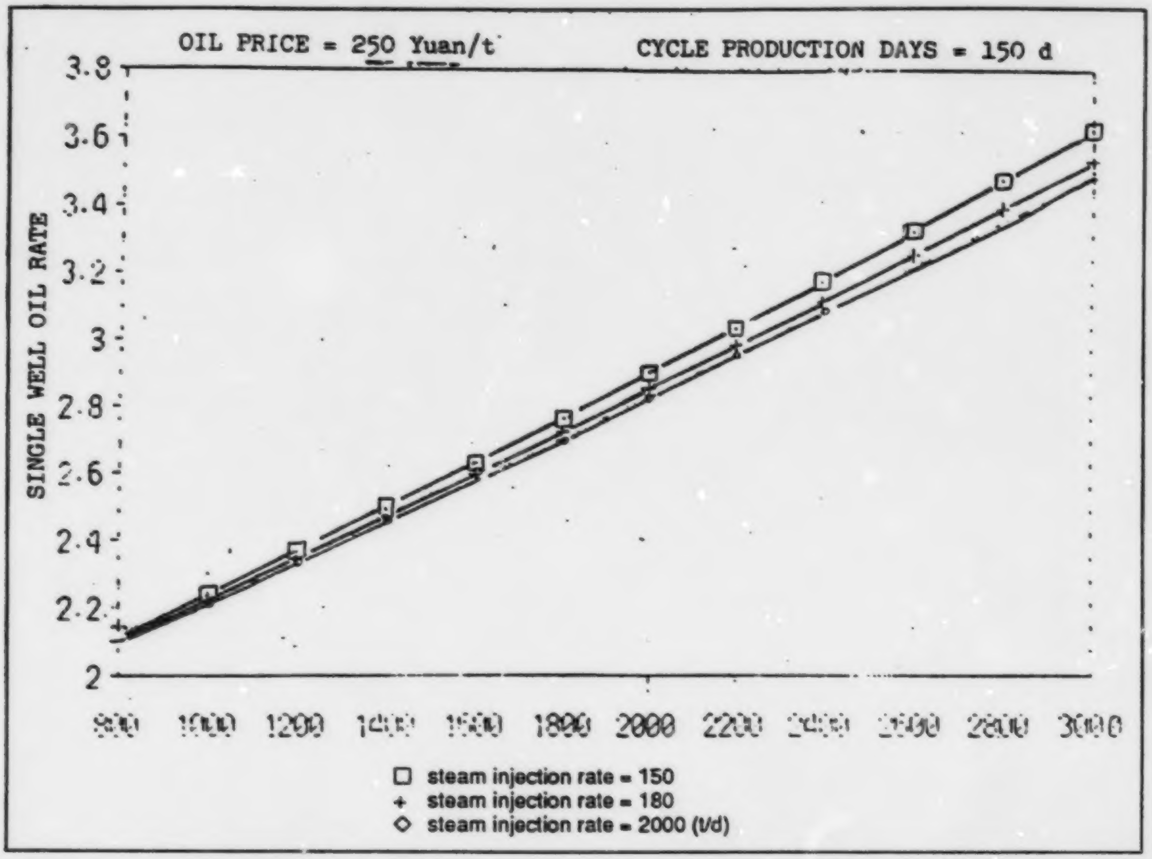

Figure 3. Steam stimulation single well production limit in District No. 9.

To choose a reasonable well spacing for practice is a complex procedure. In addition to considering the heating area, investment, oil recovery, and profits should also be taken into account. Thus, well spacing can be selected based on the results of economics, reservoir analyses, numerical simulation, and correlation methods between production practices and pilot tests.

By using the mentioned methods for the reservoirs with oil viscosity of less than 10,000 mPa·s and net pay of 10 to 20 m, the well spacing for heavy oil reservoirs in District 9(6) of Karamay oil field should be 10,000 to 20,000 m^2. This corresponds to the well distance between 70 to 100 m in the five-spot patterns and could be operated by steam stimulation followed by steamdrive. On the other hand, well spacing should be increased slightly for reservoirs with lower oil viscosity.

OPERATION PARAMETERS FOR STEAM INJECTION

The successful heavy oil recovery by steam injections depends on geological conditions, well patterns, and steaming operation parameters.

Steam Injection Pressure and Temperature

Operators always want to have the injected steam with higher temperature. However, for a saturated steam, the higher steam temperature exists with higher steam injection pressure. Thus, during high temperature steam injection, the following conditions are likely to occur infield practice:

1. If steam injection pressure exceeds formation breakdown pressure, this will result in early steam breakthrough along fractures and reduce steamdrive recovery efficiencies.

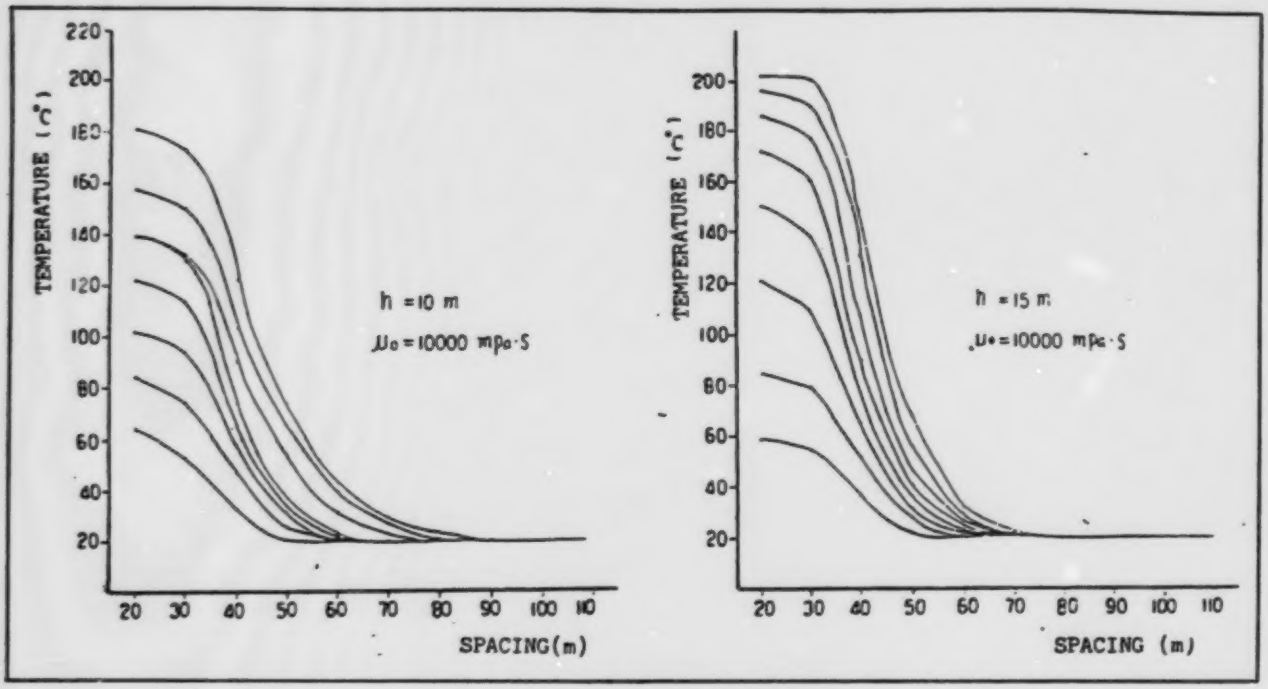

Figure 4. Temperature distribution figure.

2. If casing, wellhead and packer are damaged by excessive steam pressure, it will be difficult to control steam injection. This will also affect steam-drive recovery.

As indicated above, steam pressure and temperature must be controlled during steam injection. Generally speaking, for heavy oil reservoirs with oil viscosity of less than 20,000 mPa·s, three to six cycles of steam stimulation could be followed by steamdrive. In this case, steam pressure must be controlled under formation breakdown pressure. However, reservoirs with oil viscosity of more than 20,000 mPa·s are mainly recovered by steam stimulation, and steam might be injected at a pressure exceeding breakdown pressure. This is because steam injectivity is limited by very low oil mobility in the formation, the fractures created by high pressure steam could increase steam rates, and sufficient steam can be injected into reservoirs to improve recovery efficiencies.

Cyclic Steam Injection Volume

Field tests and numerical simulation results show that cyclic steam injection volume has a significant effect on oil recovery efficiencies and economics. The cyclic steam injection volumes are determined by reservoir net pay and oil viscosity. For reservoirs with thin oil zones, however, the steam volume should be given more in order to compensate the heat loss to the surroundings. Cyclic steam volume increases with oil viscosity. Moreover, it should increase with the cycle number.

The study of heavy oil reservoirs in District 6-9 of the Karamay field suggested that reservoirs with net pay of 10 m and oil viscosity of 10,000 mPa·s, requires steam injection volume of 1,100 to 1,200 tonnes or 110–120 tonnes/meter (Figure 5). When net pay in reservoir is 20 m, cyclic steam injection volume should be 1,680 to 1,800 tons or 80 to 90 tonnes/meter (Figure 6). For an oil reservoir with a net pay of 10 m and an oil viscosity of 50,000 mPa·s, the cyclic steam injection volume should be 2,000 to 2,500 tonnes or the steam volume per net pay should be 200 to 250 tonnes/meter.

Timing for Project Conversion from Stimulation to Drive

Heavy oil reservoirs, which meet the screening criteria for steamdrive process as described above, should be converted to steamdrive after a period of steam stimulation. The conditions and timing for project conversion are described as follows:

(a) Heat communication is nearly established between injectors and producers during steam stimulation phase.

(b) Residual oil saturation after steam stimulation should be 0.45–0.5 in order to provide sufficient mobile oil saturation for steamdrive process.

(c) Reservoir pressure might decrease slightly after steam stimulation, but the uniform pressure gradient should occur in the formation.

(d) Oil recovery by steam stimulation is worse off.

The study of heavy oil reservoirs in District 6-9 of Karamay field indicated that better oil recovery can be obtained if steam stimulation projects are converted to steamdrive after three to six cycles.

Steam Injection Rate during steamdrive

Steam injection rate during steamdrive is an important parameter affecting oil recovery. If the injection rate is too high, the accelerated steam propagation will reduce sweep efficiency and result in early steam breakthrough. On the contrary, a low steam rate takes longer on injection time. The heat losses to the overburden and underlying zones could be significant, which will reduce thermal efficiency and oil recovery.

The numerical simulation results and pilot tests show that steam injection rate for steamdrive requires 30 to 50 tonnes/day or 1.0 to 1.67 tonnes/(m. ha. d) for shallow heavy oil reservoirs in District 6-9 of Karamay field.

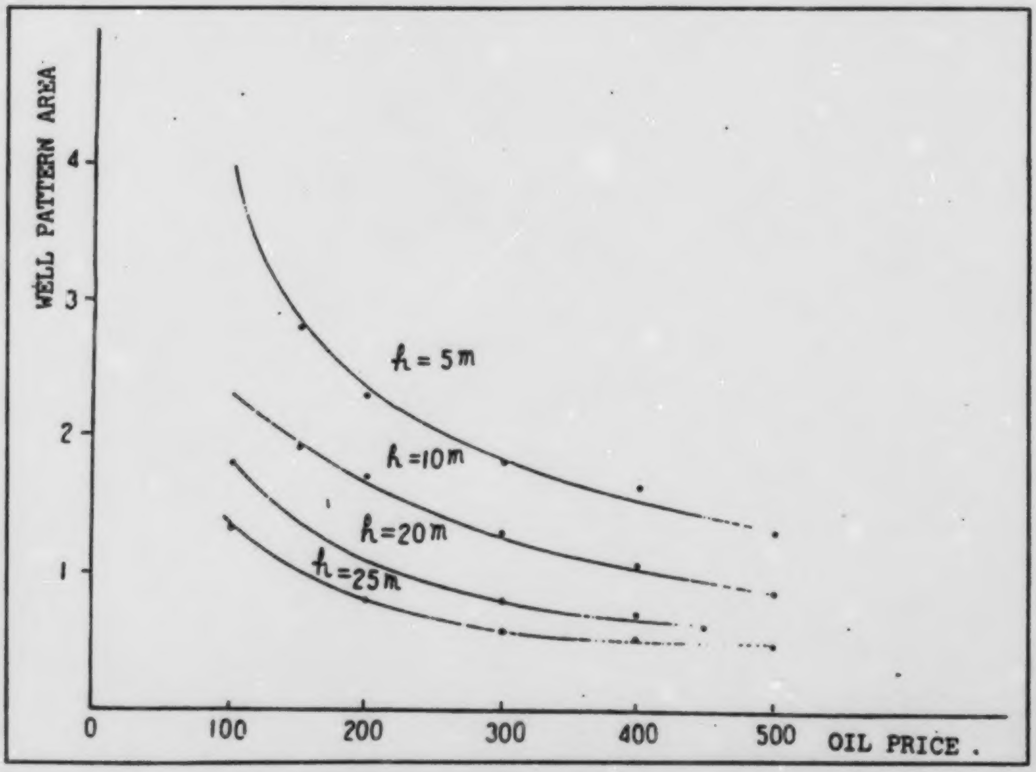

Figure 5. Steamflooding well pattern area and net thickness oil price relation.

THE FUTURE POTENTIAL OF HEAVY OIL RESERVOIR ENGINEERING STUDIES

With more heavy oil reserves developing in the world, problems with development, manpower, and technology in different countries are challenging us technically. For heavy oil reservoirs in the Northwestern margin of Junggar Basin, the following approaches are expected to be refined in the next decade.

Steam with Additives for Oil Recovery

The objectives of adding additives for steam injection are to reduce interfacial tension, block the pore throat in high permeability zones, prevent immature steam breakthrough, improve displacement efficiency, emulsify and form miscible state, and reduce oil viscosity. Laboratory and field tests on various additives have been successfully conducted in the past, and extensive applications are expected to come true soon. Future studies should concentrate on additives selection, timing for injection, procedure and amount of additives for pilot tests. Also, the effect of additives on oil properties and recovery will be stressed.

Steaming Processes for Super Heavy Oil Reservoirs

At present, super heavy oil reservoirs are widely distributed in the world, especially in Canada and China. Thus, to recover this kind of viscous oil will be our future challenge. In the province of Xinjiang, pilot tests by steam injection to recover super heavy oil have been carried out in the District 9(8) of Karamay field, and those in the Wind City field. Some of the results were encouraging, and the future potential is promising.

CONCLUSIONS

1. Through many years of thermal recovery practices in Xinjiang, the technology for heavy oil recovery has been established.
2. Heavy oil reservoir studies are an important component in developing heavy oil reserves. The accuracy and details of the studies could affect field practice and oil recovery.
3. Large amounts of heavy oil resources are present in the northwest margin of Junggar basin in Xinjiang. Through research, studies, and field tests in recent years, the accumulated knowledge and experience have helped us develop a whole set of approaches to solve engineering problems.
4. With continuous development of heavy oil recovery projects and technology, we are facing many new problems, and these should be solved by joint effort in the future.

SESSION V
Surface Facilities

SATELLITE FACILITIES DESIGN CONSIDERATIONS

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INTRODUCTION

The current trend in heavy oil drilling and production in Alberta, Canada has been the application of directional drilling which involves the use of surface facilities to collect and gather the produced fluids from different wells into satellites, and finally to transport these fluids into a central plant for treatment. Such drilling configuration minimizes land surface disturbances, lessens environmental impact of the surroundings and permits efficient land use. In addition, the benefits of energy and material conservation can also be gained.

In the design of the surface facilities for the satellites, some practical design problems such as oil-water separation, steam distribution and production gathering, vapor recovery, satellite desanding and land use have to be considered. This paper presents some effective and efficient ways of solving these problems.

TEST SEPARATORS

Well testing and monitoring are necessary steps in ensuring efficient operation of a heavy oil production field. Continual monitoring and testing of the wells provide information on the ability of a well to produce oil at any point in time. Test data will help determine what quantity of steam to inject and for how long, and when a well should be shut in because production has declined to an uneconomical level. In addition, production abnormalities can often be detected.

Test separators (Figure 1) are installed at the field satellites to facilitate such procedures. The main function of the test separators is to separate the produced gas, oil and water so as to allow accurate measurements of their relative proportions.

In Alberta, Canada, most operators prefer the use of three-phase separators over two-phase separators. The basis for this is the degree of accuracy of the net oil analyzer decreases at water cuts above 60%. A three-phase separator typically renders a water cut in

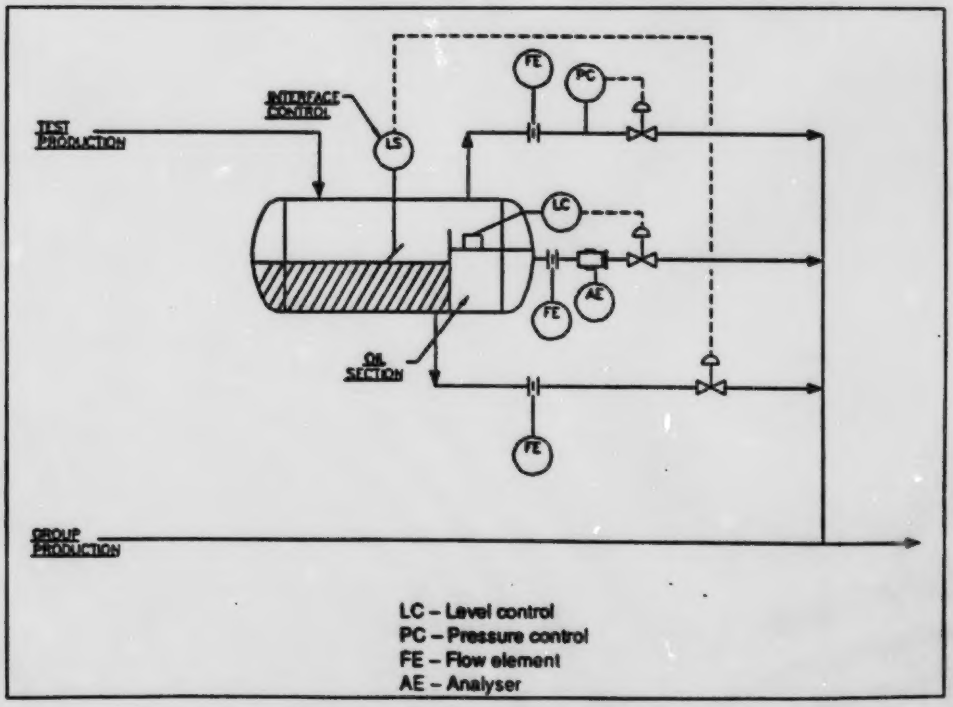


Figure 1. Three-phase test separator.

the oil phase of no greater than 40%, which is in the high accuracy range of the analyzer. On the other hand, the use of two-phase separators would result in too high a water to oil ratio.

Temperature is an important element in effective separation of water from the oil. A typical Alberta heavy oil project which produces 10–14 degree API oil, operates a test separator between 80°C and 120°C. Within this temperature range, the oil content in water will generally be less than 1% while the water content in oil will be less than 40%.

At temperatures below 80°C, satisfactory oil-water separation may still be achieved by providing greater separator residence time, it would, however, incur economic penalties of having to provide larger separators. On the other hand, inlet cooling may be necessary if fluid temperature exceeds 120°C. This is because above this temperature, the gravity of water will approach that of the oil and separation becomes difficult. At even higher temperatures, the phases will invert, causing water to be on top of the oil. When this happens, the level gauge, the interface controller and the net oil analyzer will not be able to function properly.

Often, testing of wells is not done when production temperature is too hot. This occurs during the initial days of the production cycle, but this period is usually short (from a few days to a couple of weeks). Testing starts when temperature drops down to a certain point, typically 120°C.

As an alternative to using three phase separators, a two phase separator can be used in conjunction with a sampling valve. The valve would be located in the bottom outlet line of the separator. The flow meter would measure the total flow of oil and water during the test with the sample valve taking up to ten samples per minute. These samples would be sent to a small receiver vessel that can be handled by hand. At the end of the well test the receiver oil and water content would be analysed. When the next test is started the sample valve would send samples to a new receiver. A typical receiver would hold up to 10 liters of fluid.

This system has not been proven technically and would have to be perfected before it would replace the three phase test separator; however, consideration should be given to include an additional nozzle when ordering a three-phase test separator to allow for installation of the level control so that it may be used as a two-phase separator with a sample valve installed. This is illustrated in Figure 2.

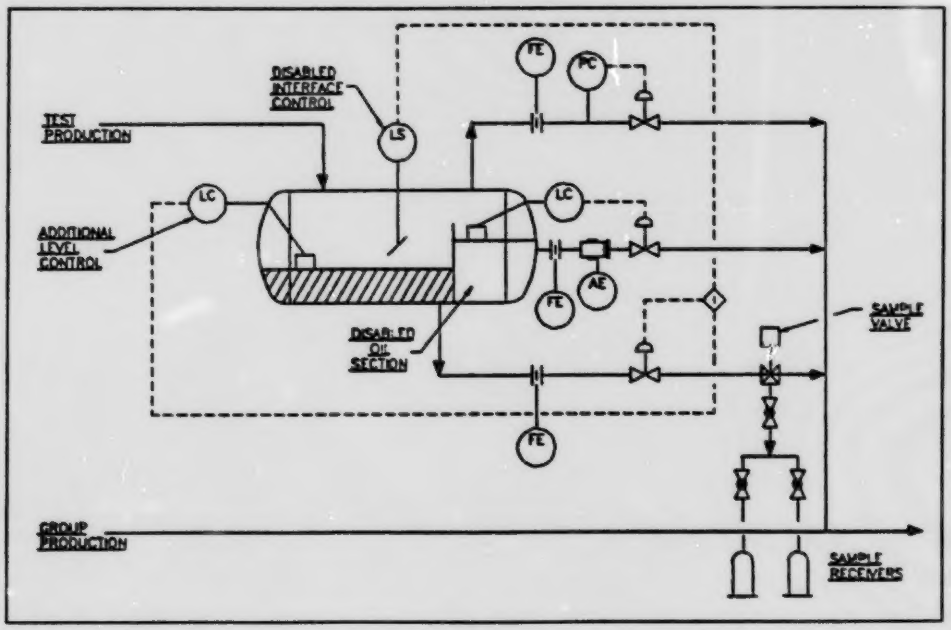


Figure 2. Three-phase separator operated as a two-phase separator with a sample valve on liquid phase.

ROTARY SELECTOR VALVES

In the design for well testing, rotary selector valves can be used to simplify the piping configuration necessary for well testings. Figure 3 is a schematic of a rotary valve which can be installed to distribute flows between production and testing. Up to 7 wells can be connected to a rotary valve which combines the individual incoming flows and discharges the combined flow to the production collection header. Whenever a well is being tested, its flow can be easily isolated and diverted to the test separator without interrupting flows from the other six wells. This reduces the number of tie-ins to the production header (see Figure 4) and simplifies the control scheme for switching the wells between production and testing. Two brands of rotary selector valves commonly used in Alberta heavy oil fields are the Erichsen Multiport Selector Valve and the LTV Energy Products Selector Valve.

STEAM DISTRIBUTION AND PRODUCTION GATHERING

Most commercial projects use steam injection to recover the viscous bitumen. Steam generated in this central plant has to be distributed to the wells for injection while production from the wells need to be transported back to the central plant for treatment.

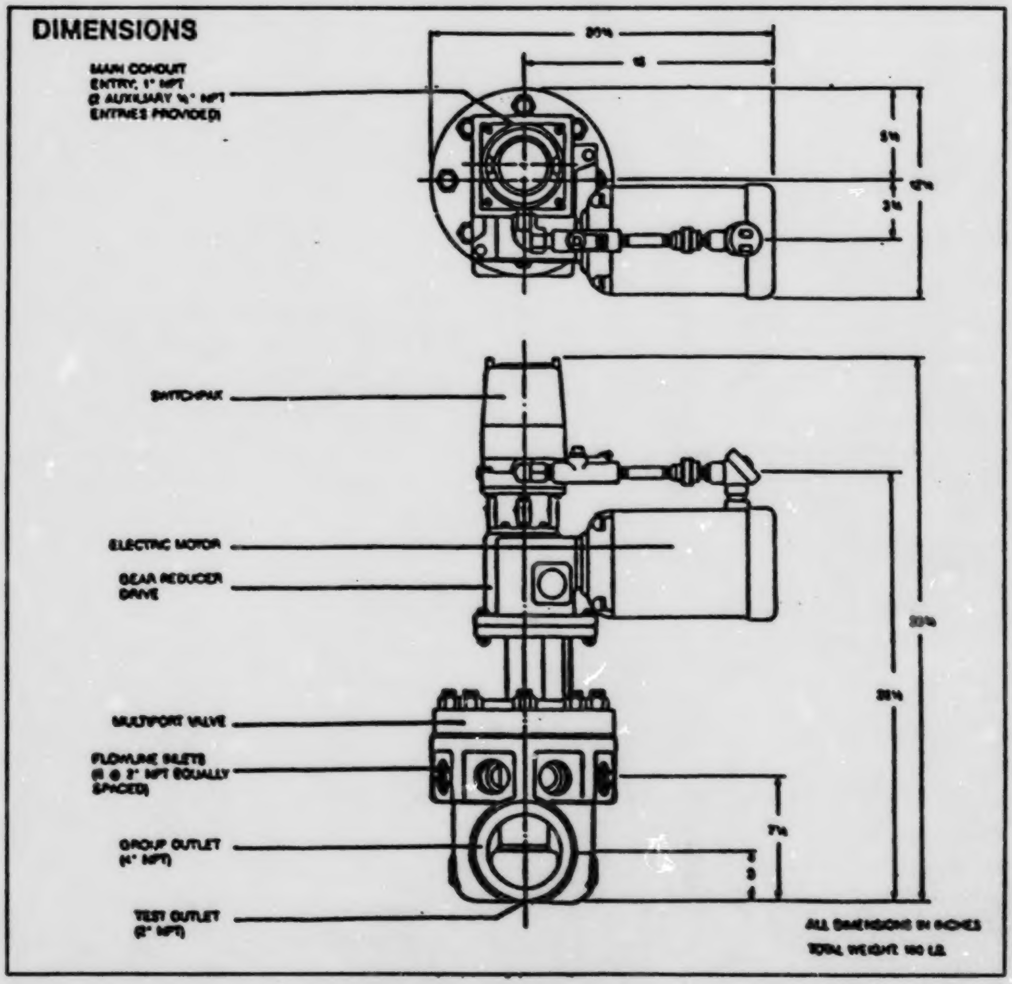

DIMENSIONS
MAIN CONDUIT ENTRY, 1" NPT (2 AUXILIARY ¾" NPT ENTRIES PROVIDED)
SWITCHPAK
ELECTRIC MOTOR
GEAR REDUCER DRIVE
MULTIPORT VALVE
FLOWLINE INLETS (8 @ 2" NPT EQUALLY SPACED)
GROUP OUTLET (4" NPT)
TEST OUTLET (2" NPT)
ALL DIMENSIONS IN INCHES
TOTAL WEIGHT 160 LB.

Figure 3. Rotary selector valve.

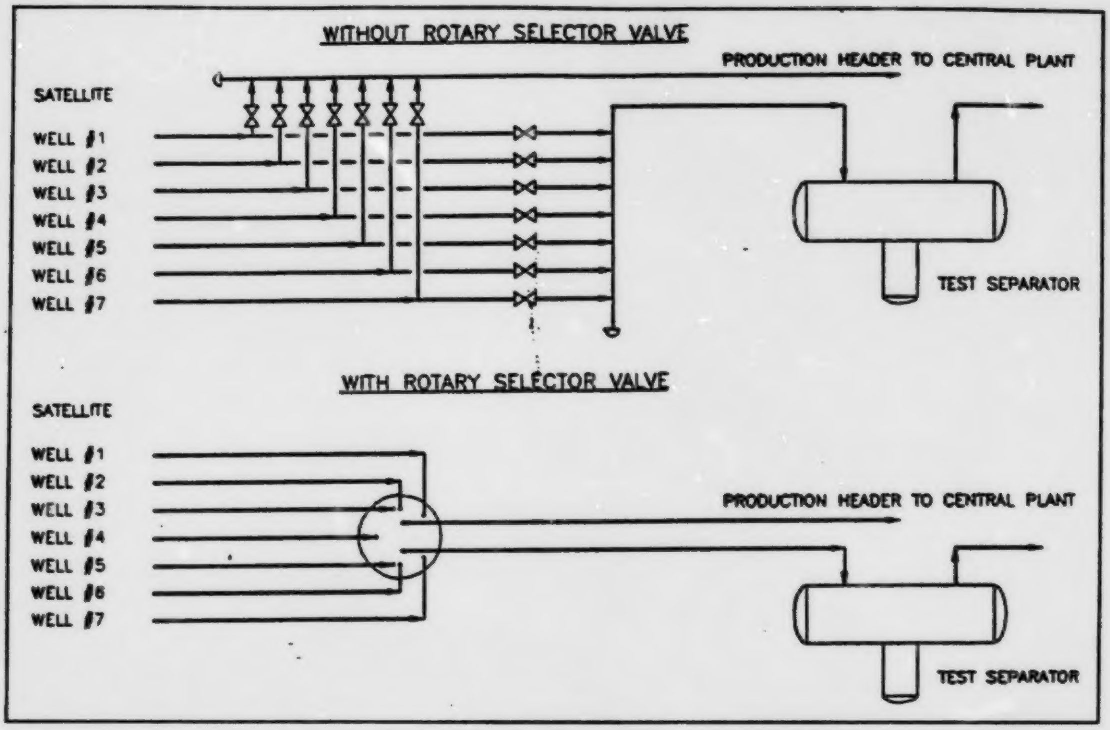

WITHOUT ROTARY SELECTOR VALVE
PRODUCTION HEADER TO CENTRAL PLANT
SATELLITE
WELL #1
WELL #2
WELL #3
WELL #4
WELL #5
WELL #6
WELL #7
TEST SEPARATOR
WITH ROTARY SELECTOR VALVE
SATELLITE
WELL #1
WELL #2
WELL #3
WELL #4
WELL #5
WELL #6
WELL #7
PRODUCTION HEADER TO CENTRAL PLANT
TEST SEPARATOR

Figure 4. Schematics illustrating how the use of rotary selector valve simplifies the piping configuration.

In the design for steam and production distribution, consideration should be given to minimizing the loss of energy. This is particularly important in areas with cold climates where the cost of energy loss is substantial. Pipelines should be insulated to reduce heat loss and to prevent line freezing. Heat tracing may also be required for freeze protection. For long pipelines, this can amount to substantial capital and operating costs.

To minimize the cost of insulation and heat tracing, individual lines can be placed together and housed in an utilidor, which is simply a rectangular insulating box. Within the utilidor, all lines can be bare except for the steam line, and other hot lines. Insulation is required for these lines to prevent excessive heat loss, but the thickness of the insulation is smaller than would be required in the case where no utilidor is used. Heat dissipated from these insulated lines and from the bare production lines is sufficient to maintain the temperature inside the utilidor well above freezing point. For typical applications, calculations indicated that the temperature in the utilidor would remain above 90°C even during a –30°C winter day. Depending upon the number of lines located in the utilidor, the cost of insulating using an utilidor may be substantially less than the cost of individually insulating the lines.

The alternative of individually insulating the field pipings may prove to be more economical in the case where the number of pipelines is small. This would be especially true for application where only a steam distribution header and a production gathering header are used.

VAPOUR RECOVERY

Well casing vent gas is a source of fuel energy that can be captured for use. In Alberta, heavy oil producers handle this gas in one of the following ways:

a. Flare the casing vent gas
b. Gather the casing vent gas to the central plant for recovery
c. Recover, compress and inject the casing vent gas into the group production line at each satellite.

Flaring the gas is usually not an acceptable option if fuel gas is in short supply. Doing so not only means loss of heating value but additional cost may be incurred when makeup fuel gas must be used in order to properly fare the casing vent as.

Option (b) involves the use of a gas gathering system which collects the casing vent gas from the wells and pipes it back to the central plant where it is compressed and discharged into the fuel gas system.

Option (c) does not require a gas gathering system for transporting the gas back to the central plant. Instead, it is compressed and injected into the production line at the satellites and is finally recovered at the central plant at relatively high pressure; compression at the central plant is not needed.

The choice between option (b) and (c) lies in the difference between the well casing pressure and production pressure. In order to inject the casing vent gas into the production line the gas has to be compressed to the production pressure. In the case where the production pressure is much higher than that of the casing gas, much energy will have to be expended in compressing the gas; staged compression may be necessary. Under these circumstances option (b) is probably more economical. Such is the case with the Shell Peace River Project in Alberta where a central plant vapor recovery system is utilized. The alternate scheme would be substantially more expensive.

SATELLITE DESANDING

Due to the viscous nature of heavy oils, sands and other solids in the formation often get carried up to the producing wellhead. At satellite pads where test separators are installed to monitor and evaluate the performance of the wells, these particles, if produced in significant quantities and are not removed, can cause plugging problems, leading to inoperable test separators. It has been estimated that sand control is necessary when sand production exceeds 0.5% (vol.) of the gross produced fluids.

One of the proven methods to desand separators is to fluidize the accumulated sands by high pressure water jets. The fluidized sands/water mixture is then withdrawn and piped to a settling tank where the sands settle out and the water is reused. Desand pans are installed in the separator to facilitate such operation. A typical desanding system is shown in Figure 5.

Desanding systems are usually automated with a manual override. A typical cycle is to desand for two minutes. After each desanding process, the desand return line to the tank is flushed with clean desand water to ensure that no sand builds up in the lines.

It must benoted that desanding system is not usually installed for a test separator unless sand volumes are abnormally high. Rather, the separator is shut down periodically to remove the accumulated sand. During this procedure, well testings are disrupted; but this should not be a major problem since the time periods between cleaning will be fairly large (between 6 months to 1 year) and the length of time for cleaning will be short (typically less than 1 day).

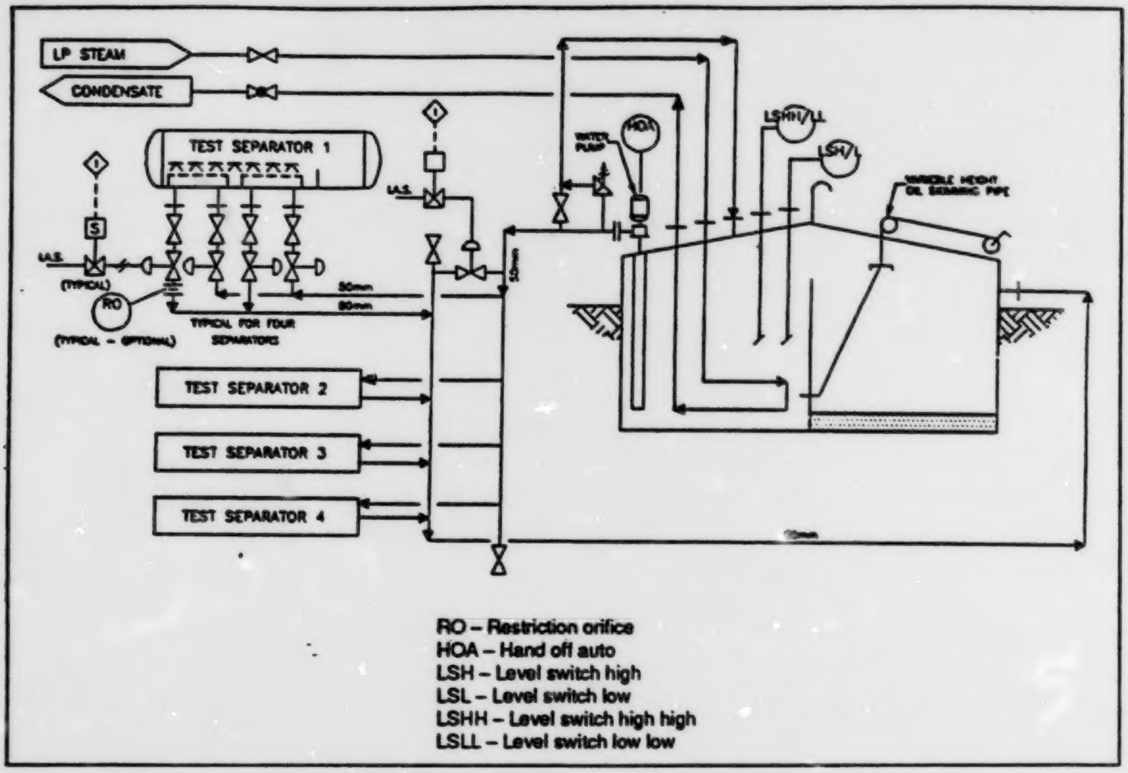
LAND USE CONSIDERATIONS

Directional drilling allows many wells to be drilled over relatively small satellite pads thereby minimizing land surface disturbances and environmental impact. The number of pipelines is greatly reduced by such drilling configuration as compared to straight well drilling, thus taking up much less usable land space. Moreover, with straight drilled wells, equipment and pipelines are scattered over a wide area, hindering mobility in the region.

Further land use reduction can be achieved by systematic planning such as adapting an efficient piping layout and running access roads along pipelines.

SUMMARY

An effective and efficient design of satellite surface facilities needs to address practical problems such as oil-water separation, steam and production distribution, vapor recovery, satellite desanding and land use.


LP STEAM
CONDENSATE
TEST SEPARATOR 1
I.A.S.
(TYPICAL)
RO
(TYPICAL - OPTIONAL)
TYPICAL FOR FOUR SEPARATORS
50mm
80mm
TEST SEPARATOR 2
TEST SEPARATOR 3
TEST SEPARATOR 4
WATER PUMP
HOA
LSHH/LL
LSH/L
VARIABLE HEIGHT OIL SKIMMING PIPE

RO – Restriction orifice
HOA – Hand off auto
LSH – Level switch high
LSL – Level switch low
LSHH – Level switch high high
LSLL – Level switch low low

Figure 5. Satellite desand system.

Continual well testing is desirable to monitor performance and facilitate production planning. Effective oil-water separation generally occurs at 80°C–120°C. Three phase test separators are normally used, although two phase separators with sampling valves, if technically proven, can be used instead to give better test accuracy.

The use of utilidors can be an economical way of insulating lines especially when the number of lines is large, but a study should be done before making the choice.

A study has to be done to determine if Central Plant Vapor Recovery is more economical than Satellite Vapor Recovery.

Satellite desanding is necessary when sand volumes are abnormally high. The principle of desanding involves fluidizing the accumulated sands with high pressure water jets.

Finally, reduction in land use can be achieved by adapting directional drilling and systematic planning of piping layout and access roads

THE AOSTRA TACIUK PROCESS TECHNOLOGY FOR OILFIELD CLEAN UP OF TANK BOTTOMS AND E.O.R. PRODUCTION WASTES

Douglas P. Komery
Alberta Oil Sands Technology and Research Authority Calgary, Alberta

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INTRODUCTION

It is becoming increasingly necessary for industry to be more accountable for wastes produced in the course of conducting business such as production and refining of resources or the manufacture of goods, and to maximize efficient use of resources used to produce goods and services. Due to the energy base of modern economies and the sophisticated chemical and petrochemical products used by most societies, a large portion of industrial waste is soils and sludges which are contaminated by hydrocarbons, oil or organic chemicals. Waste materials are an industrial and social liability, and as legislation forces action, the oil and petrochemical industries must seek the most economical options available for remediation of oily waste, as well as seek to maximize use of, or recycle the contaminating materials in the wastes.

The AOSTRA Taciuk Process (ATP) is a thermal treatment technology which separates and processes certain contaminating components from host materials, offering significant cost savings over thermal treatment methods, such as incineration which destroys the organic contaminants. The ATP effluent or oil product may be re-used, separately treated or disposed of in an efficient and economical manner. The treated solids residue portion of the material is usually environmentally safe, and may be disposed of without further treatment.

The ATP technology was developed jointly by the Alberta Oil Sands Technology and Research Authority (AOSTRA) and UMATAC Industrial Processes (UMATAC) over a 14 year period. A pilot scale research and development facility was constructed in 1977 in Calgary, Alberta for the development of the Process and plant equipment. This facility comprises a small scale batch testing apparatus, and a continuous flow 4.5 tonne/hour pilot Processor unit and plant. The facility is supported with a laboratory and personnel services. The pilot unit is capable of continuous operation with staffing available to maintain around-the-clock, 24 hour/day operation.

AOSTRA has expended more than $18 million in the development of the ATP. The process was originally conceived and developed for the extraction and primary upgrading of bitumen from mined oil sands in the Athabasca region of Alberta. It has been tested extensively for the processing of oil shales and most recently it has been demonstrated to be effective for treating soils and sludges which are contaminated with oil and other organic wastes.

This recent work with oily wastes resulted in the construction of the first commercial ATP waste treatment plant in 1989. A 10 tonne/hour transportable plant was built and supplied to the remediation of contaminated sites in the United States. It is presently working on the remediation of a PCB-contaminated site in New York State.

The ATP System offers distinct advantages over other large scale technologies applicable to remediation treatment of soils and sludges, such as incineration and solvent extraction. These include:

- the separation and concentration of the hydrocarbon constituents making it possible to individually re-use, treat or dispose of them as required to meet environmental requirements.

- treated solids which are environmentally acceptable, and usually meet leaching criteria.
- energy efficiency through use an efficient internal heat recovery system, which preheats the incoming feed by cooling the exiting combusted solids residue and flue gases, resulting in reduced fuel consumption.
- an anaerobic atmosphere for treating the waste material as it is processed at the higher temperatures required for pyrolysis.
- simple and safe operation. The process vessels operate at near atmospheric pressures, a single vessel produces the extracted process vapors, and is capable of almost instantaneously quenching the process reactions in an emergency operating condition.

Energy efficiency, and corresponding lower costs, are demonstrated by comparison with incineration, a thermal technology which is commonly used for treating wastes. Incineration treatment usually requires that the temperature of the entire feed be raised to 1100°C or greater. In comparison, the ATP heats the liquid portion of the feed to temperatures up to 600°C and the solids to temperatures of up to 750°C. This results in significant energy savings over incineration. Also, incineration requires large amounts of combustion air to completely burn and destroy all of the organic material in the feed. This results in very large flue gas emission rates at high temperatures as compared to the ATP System.

PROCESS DESCRIPTION

The ATP is a thermal extraction process for separating hydrocarbons from granular host solid materials. The process occurs in a rotary vessel, or Processor, which preheats, vaporizes, pyrolyzes, removes hydrocarbon vapors, burns coke byproducts and recovers heat from the treated solids as they exit the vessel. Products from the process are: hydrocarbon vapors, steam, gases of combustion, and inert residual tailings solids.

Two major sub-systems provide condensation of hydrocarbon vapors and flue gas treatment. Refer to Figures 1 and 2 to trace the process streams, which are described as follows.

The contaminated feed material enters the Preheat Zone where water is evaporated from the feed, providing a steam blanketing atmosphere which reduces oxygen levels. Air which has entered with the feed, vaporized light oil and steam are extracted from this zone, and are condensed elsewhere in the plant. The oil and water are condensed, separated, and then sent for storage, disposal or treatment as required. Noncondensable gases from the Preheat, reduced mostly to air, are directly injected into the Combustion Zone.

Within the Processor, the preheated material is transported to the Reaction Zone where it is mixed with hot recycle solids to further heat the incoming feed stream to higher temperatures. In the Reaction Zone, lower boiling hydrocarbons are vaporized and any higher boiling hydrocarbons may be thermally cracked by pyrolysis. This process produces two streams — a vapor stream comprising gas and liquid fractions, and a coke residue which is deposited on the solids. These streams are then separated. The coked solids are routed to the Combustion Zone, and the hydrocarbon (HC) vapor stream is extracted from the Reaction Zone and Process vessel.

The H-C vapor stream is drawn through a cyclone to remove entrained solids, then to a vapor scrubber to perform the first stage of vapor cooling and capture of fine dusts. The fine dusts are collected in the condensed, heaviest hydrocarbon fraction, called bottoms oil. This bottoms oil may be used as a fuel for the Processor, or recycled for re-pyrolysis to extinction, thus eliminating the dust loading and the heaviest oil fractions of the oil product. In the case of processing hazardous components in the feed, the bottoms oil may also be directed to disposal as a hazardous liquid.

The cleaned, cooled vapors are directed to the fractionator for separation and condensation of the hydrocarbons into two fractions — heavy and light oils. The light oils and vapor from the top of the fractionator are drawn through a heat exchanger for condensation and separation. The heavy oils are collected in the fractionator sump.

These oil products may then be directed to product storage. The overhead water, which is

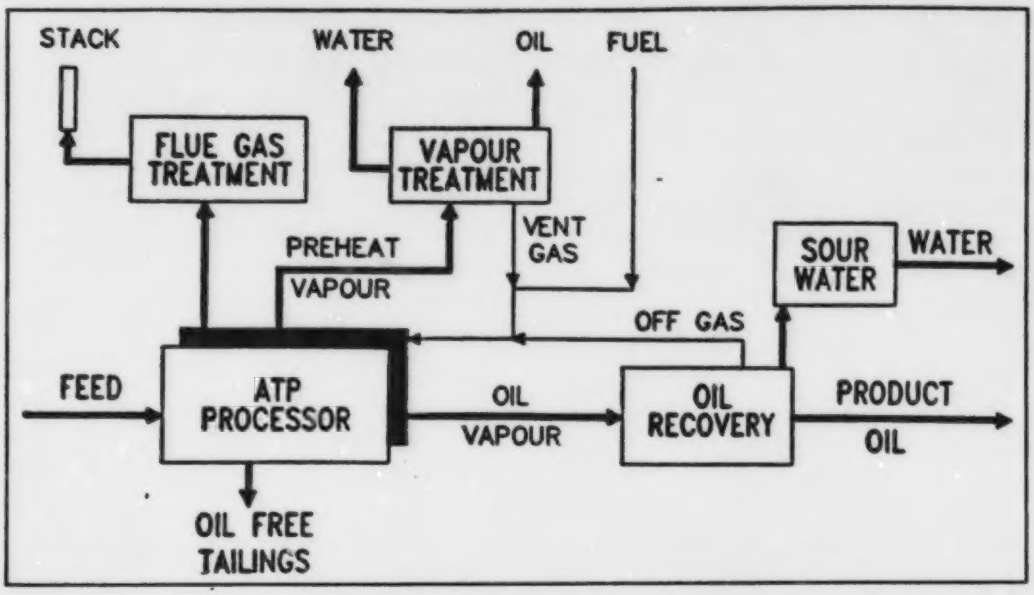
STACK
WATER
OIL
FUEL
FLUE GAS TREATMENT
VAPOUR TREATMENT
VENT GAS
PREHEAT VAPOUR
SOUR WATER
WATER
OFF GAS
FEED
ATP PROCESSOR
OIL VAPOUR
OIL RECOVERY
PRODUCT OIL
OIL FREE TAILINGS

Figure 1. AOSTRA Taciuk Process (ATP).

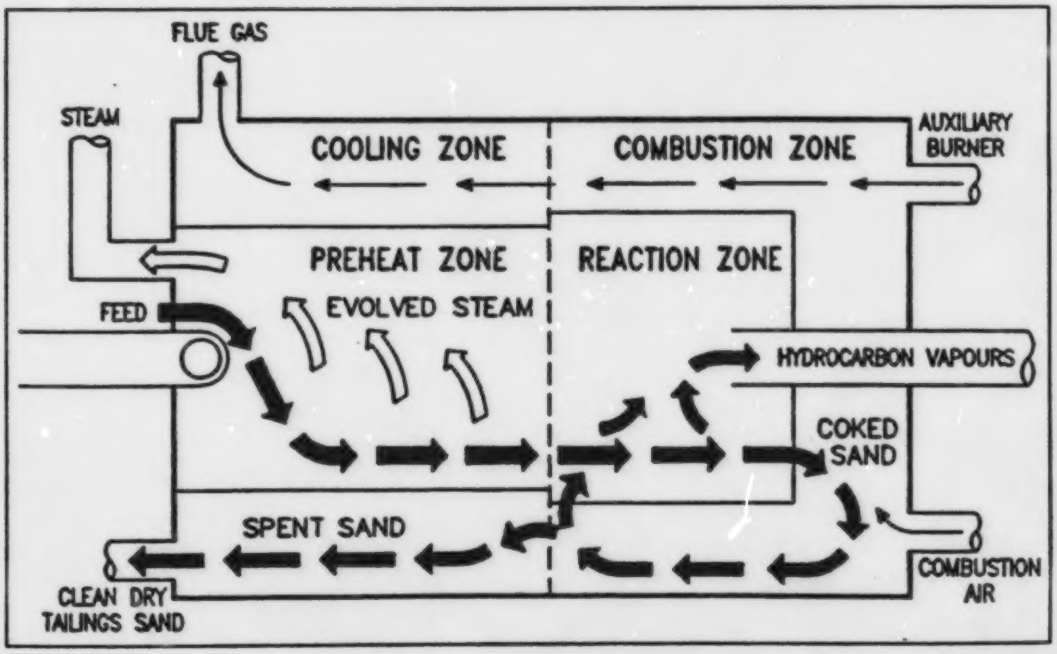
FLUE GAS
STEAM
COOLING ZONE
COMBUSTION ZONE
AUXILIARY BURNER
PREHEAT ZONE
REACTION ZONE
EVOLVED STEAM
FEED
HYDROCARBON VAPOURS
COKED SAND
SPENT SAND
COMBUSTION AIR
CLEAN DRY TAILINGS SAND

Figure 2. ATP processor internal process flows.

generally sour, may be optionally stripped of organics, and then sent offsite for further treatment. The noncondensable gases may be burned for fuel in the Combustion Zone, directly or through an auxiliary burner, or they may be flared, as required.

The coked solids residue deposited on the solids during pyrolysis is burned in the Combustion Zone to heat the solids and to fuel the process. Auxiliary burners, firing industrial fuels, are provided to supplement the heat generated by the combustion of the coke. A slip stream of the hot combusted solids is recycled to the Reaction Zone, and the remainder passes to the Cooling Zone.

The Cooling and Preheating Zones act as a countercurrent heat exchanger in which hot spent solids give up heat to the incoming feed. The heat exchange is indirect, providing isolation of the hot inert treated solids from the incoming contaminated feed.

The discharged solids, or tailings, having transferred most of their contained heat to the incoming feed, are dampened with water to provide further cooling and dust control, and are conveyed to stockpile. The steam produced is vented directly to atmosphere, or condensed, as required.

The flue gases from combustion are first treated by passing through a cyclone, followed by filtering through a baghouse, wet scrubbing of acid components, and are finally discharged from an exhaust stack. Additional treatment, such as carbon filtration, can be added if required. The baghouse and cyclone solids are discharged with the Processor solids to a stockpile.

PROCESS CONDITIONS

The above describes the four distinct zones of operation within the ATP Processor — the Preheat, Reaction, Combustion and Cooling Zones. The typical conditions of process within these zones are described.

The Preheating Zone is designed to raise the temperature of the feed from ambient conditions to some elevated temperature appropriate to the feed type. The processing of oils with light hydrocarbons would require lower vaporization temperatures than would heavier oils. Evolved vapors and steam are extracted from the zone, depleting the zone's atmosphere of oxygen. Preheat Zone exit temperatures are 200 to 300°C.

The Reaction Zone completes the extraction of remaining hydrocarbons from the solids charge. This process takes place in an anaerobic atmosphere. The feed characterization determines the extent to which this zone must perform; whether vaporization is sufficient for extraction or if thermal cracking at higher pyrolysis temperature is required. Generally, operation on oily waste requires temperatures in the range of 400 to 600°C.

The Combustion Zone provides heat for the process at temperatures of 600 to 750°C as necessary for the Preheat and Reaction Zone functions. Auxiliary fuel burners are available for startup and to supplement the heat requirements during operations on feed containing low hydrocarbon levels. Higher molecular weight oils in the feed will produce coke when pyrolyzed. The coke is burned as fuel in this zone, reducing the requirements for heat from auxiliary fuels.

The Cooling Zone accepts hot residual solids discharged from the Combustion Zone, from which heat is transferred to the Preheat Zone. The degree to which the treated solids are cooled is directly related to the heating objectives of the Preheat Zone, as described above. Typically the cooled solids are discharged at 250 to 350°C.

If the required heat loading is very high, as in the case of a highly liquid feed, additional recycle solids may be circulated directly into the Preheat Zone. This increases the circulation solids load, providing the additional thermal mass to boost and regulate the temperature in the Preheat Zone.

All four zones are maintained at sub-atmospheric pressures by the automated control instrumentation. The Combustion and Cooling Zones are automatically maintained at a pressure of –1 mm water column (WC) gauge by means of an induced draft fan at the flue gas handling area. The Preheat Zone pressure, of about –1 mm WC, is maintained by means of a vacuum compressor downstream of the vapor condensation system. Lastly, the Reaction Zone is maintained at a pressure slightly less than any of the other three zones in order to prevent release of the products of pyrolysis or vaporization. A vacuum compressor downstream of the vapor condensation and handling systems provides the draft for the Reaction Zone vapors. Typical operating pressures in the Reaction Zone are in the range of –1 to –2 mm WC.

APPLICABILITY TO VARIOUS FEEDS

The ATP is capable of processing a wide variety of feed types. Originally intended to process oil sands with upwards of 17% by weight of oil and water, the ATP System and Processor operation can be adjusted to handle such widely varying feed materials as slurries, approaching 100% liquid, and dry, organically contaminated soils. Since commencing testing in 1978, the pilot plant has processed over 14,000 tonnes of oil sands and oil shales. Testing of wastes began in 1985 and has consumed a further 500 tonnes of oily soils, emulsions and slurry wastes from the oil production, enhanced oil recovery and oil refinery industries. Hazardous waste processing has included nearly 30 tonnes of PCB-containing oily soils. The commercial ATP plant was used in 1989, to treat approximately 1000 tonnes of oily wastes during testing and demonstration, prior to being put to commercial operation.

Although basically a solids handling machine, the Processor is capable of treating slurries and high liquid content feeds which may be injected directly, while simultaneously processing a continuously recycled charge of carrier solids. Alternately, the liquid feed can be pre-mixed with a recyclable carrier solids stream prior to entering the Processor.

The ability of the Processor to handle and process oversize materials and objects in the feed is limited, and dependent on the size of Processor in the plant facility. Processors with throughput capacity in the range of 10 tph can handle objects to size approximately 200 mm, but can treat to size about 50 mm.

The capability and viability of treating a waste with the ATP may be determined through a treatability test program in which UMATAC uses small scale batch testing apparatus. This program has been used successfully to screen numerous potential waste feeds for the 4.5 tonnes/hour pilot plant unit. The hydrocarbon yield, the organic component distribution, and the environmental characteristics of the treatment products are well represented and examined by batch scale testing. In some instances, a continuous progression of batch, pilot and the commercial 10 tph operation have been completed.

Table 1 lists some of the feed materials evaluated for the ATP and the stage of evaluation. One of these programs was conducted on oily waste soils and sludges from the Canadian oil field operations. Summary results of this work are described, and are indicative of and similar to, the capabilities of the ATP System and results obtained from other programs.

Table 1. Feed materials tested by the ATP system

Feed material	Batch unit	Pilot (4.5 tph)	Commercial (10 tph)
Resource Processing			
Low grade oil sands	•	•	
Average grade oil sands	•	•	
High grade oil sands	•	•	
U.S. low grade oil sand/shale	•	•	
U.S. high grade oil shale	•		
Utah oil shale	•	•	
Malagasy oil sands	•	•	
Australian oil shale	•	•	
Lloydminster heavy oil	•	•	
Rubber tires	•	•	
Brazilian oil shales	•		
New Zealand peat moss	•	•	
Israeli oil shales	•		
New Brunswick oil shales	•		
Waste processing			
Refinery cleanup wastes	•	•	•
Refinery alkylation wastes	•		
Coal tar residues	•		
Invert drill mud cuttings	•	•	•
Oil field desand sludges	•	•	•
Oil field tank sand	•	•	
PCB oily waste	•	•	

TREATMENT OF HEAVY OIL PRODUCTION WASTES

In 1986, AOSTRA and UMATAC commenced a two phase program to test the capabilities of the Processor and ATP System for the treatment of various heavy oil production wastes obtained from the heavy oil and oil sands bitumen producing area bordering the provinces of Alberta and Saskatchewan. The program was sponsored by Environment Canada, and also supported by Supply and Services Canada and Energy Mines and Resources Canada.

The Lloydminster-Lindbergh heavy oil area in these provinces produces about 90,000 cubic meters per year of oily wastes. Lesser, but increasing volumes are generated in the Cold Lake bitumen-producing area of Alberta. The waste products of heavy oil and in-situ bitumen production are defined as follows:

a) Field Tank Sand accumulates as drop out solids in the small tanks located at or near individual production wells. These sands are periodically collected by truck and carried to a central collection pit for holding, or to other disposal. Oil content is usually less than 5%.

b) Desand Pit Sludge collects from the battery treater operation. The sandy sludge collects over a period of time in the tank or pit, which is periodically cleaned out to permit ongoing operation. The oil content of the sludge varies widely between 7% and 40% by weight.

c) Slop Oil and Slop Oil Solids are sand-bearing liquids or sludges which usually contain an oil-water emulsion. The emulsion prevents separation of the oil by density. Oil-water-solids contents vary widely, with solids ranging between 10% and 50%. These wastes are usually collected and held temporarily in tanks or pits.

d) Spill Debris is usually soil which has been contaminated with oil from an accidental spill. Sometimes soil is added to spilled oil to aid in the cleanup. Hay and straw are also used as absorbents. Spill debris is normally collected in a central holding pit, from which it is periodically removed for disposal.

e) Ecology Pit Mixture is a composite of the above individual wastes. The ecology pits are central holding facilities which must be periodically emptied to permit ongoing operations. The mixture makeup varies widely in proportion of each wastes. The pit also serves to mix the liquids and dry wastes to make a more handleable composite.

The test and demonstration program included two phases of testing, plus associated laboratory analytical work and engineering evaluation. The initial testing, called Phase I, consisted of small scale bench and batch scale work which characterized the wastes and provided broad indication of the likely performance of the ATP in treating these materials. The test work of the second phase (Phase II) was done on bulk samples of four of the wastes screened in Phase I, for which the 4.5 tph pilot process plant was used. This work and summary results are described.

PHASE I – BATCH TESTING

Treatability testing experiments were carried out in existing batch equipment at the Calgary pilot plant to examine both the pyrolysis and residual coke combustion operations which would occur in the Processor when fed with these oil field wastes. A total of 17 different heavy oil production wastes, as listed in Table 2, were tested in Phase I.

These samples were extremely variable in terms of contents of oil, water and solids, and in terms of their respective concentrations of inorganic ions. Variations depended on the waste type and the source of the sample, as evidenced from the data presented in Tables 3 and 4.

In the batch pyrolysis apparatus the performance of each candidate feed was evaluated over a range of process operating conditions, such as temperatures, purge rates, simulated solids recycle and mixing energies. The produced oil, water, off-gas and coked solids were recovered. The quantity of each was measured for material balancing, and samples were taken for analysis.

The analytical work performed on product samples from the batch pyrolysis tests on the 17

Table 2. Oil field wastes for the ATP treatment test and demonstration program

Phase I

	Source	Type
1.	Tangleflags	Field tank sand
2.	Lloydminster	Slop oil/sludge
3.	Wolf Lake	Slop oil/sludge
4.	Wolf Lake	Desand sludge
5.	Wolf Lake	Heavy oil
6.	Lloydminster	Composite
7.	Lindbergh	Desand sludge
8.	Lloydminster	Field tank sand
9.	Cold Lake	Desand sludge
10.	Celtic	Desand sludge
11.	Lindbergh	Field tank sludge
12.	Lloydminster	Desand sludge
13.	Lindbergh	Desand sludge
14.	Brooks - Light oil waste	Pit sludge
15.	Lloydminster	Ecology pit mixture
16.	Lloydminster	Heavy oil
17.	Lloydminster	Sludge

Phase II

Source	Type	% in feed	Hours	Tonnes
Mobil Celtic	Desand sludge	56	116.5	138
Mobil Kitscoty	Field tank sludge	100	41.2	85
BP Wolf Lake	Desand sludge	34	12.5	52
Esso Cold Lake	Desand sludge	47	23.7	106
Combustion trials	Coke & coked sand		36	
Totals			222.9	381

Table 3. Averaged constituent analysis data – Phase I all waste feedstocks

	Average for field tank sand	Average for desand sludge	Average for heavy oil	Average for Lloyd composite
Proximate analysis				
material density	1.21	1.04	0.98	1.24
wt% oil	7.00	35.86	92.75	14.85
wt% water	11.03	28.09	5.35	10.56
wt% solids	81.60	35.13	2.25	73.70
wt% sulphur	0.40	1.71	3.37	0.64

	East Lloyd	Wolf Lake/Cold Lake	Lloydminster	Lindbergh	Brooks
Proximate analysis					
material density	1.33	1.26	0.81	1.15	0.73
wt% oil	15.45	32.35	16.44	28.60	87.00
wt% water	16.00	34.45	17.38	23.40	9.85
wt% solids	67.15	32.70	64.88	48.07	1.64
wt% sulphur	0.78	1.95	0.78	1.52	2.33

***Table 4.** Averaged constituent analysis data – Phase I. All waste feedstocks*

	Field tank	Desand sludge	Heavy oil	Lloyd composite	East Lloyd	Wolf Lake Cold Lake	Lloyd–minster	Lind–bergh	Brooks
Indicator Chemistry (values in ppm; negative values denote less than detection limits)									
aluminum	94.66	107.34	3.18	1074.12	8.60	90.23	498.66	8.02	11.70
barium	8.48	8.88	0.24	170.03	6.63	9.03	63.25	4.20	4.50
beryllium	–0.10	–0.01	0.06	0.02	–0.10	–0.10	–0.00	–0.10	–0.10
boron	3.38	11.65	1.44	6.00	4.77	18.47	4.83	5.22	1.80
cadmium	0.00	1.27	–0.06	–0.06	0.16	2.26	0.29	0.09	–0.10
calcium	640.67	4733.13	34.90	3440.00	2383.00	7639.40	2223.70	907.00	83.20
chromium	1.16	3.86	0.12	1.05	0.80	6.61	1.67	0.86	–0.10
cobalt	1.05	3.36	0.05	2.82	0.48	5.38	2.30	0.89	0.20
copper	0.98	3.33	0.14	2.85	0.47	4.00	3.31	0.57	0.40
iron	400.45	284.35	2.73	15.01	–0.27	5.00	622.95	0.37	37.70
lead	10.40	23.34	1.47	23.60	3.50	40.85	17.62	4.37	2.20
lithium	6.51	9.87	0.59	0.91	6.05	13.93	4.02	6.26	0.60
magnesium	250.33	617.20	9.20	567.50	341.00	568.50	468.57	556.00	23.80
manganese	10.42	8.05	–0.14	17.16	3.02	1.31	17.94	5.74	1.60
molybdenum	1.70	12.39	1.83	3.25	0.99	23.37	3.51	3.24	0.50
nickel	3.48	7.85	13.25	10.57	1.13	11.31	12.01	2.23	2.50
potassium	112.77	219.59	4.32	221.50	107.80	281.18	142.44	173.61	50.30
silicon	45.23	143.21	4.50	206.50	69.55	242.19	83.57	78.03	3.20
sodium	1251.67	2173.33	55.90	2925.00	1920.00	1189.20	2184.17	2475.00	150.00
strontium	14.13	44.57	0.29	62.70	47.85	36.56	40.09	28.17	2.50
titanium	2.57	1.99	0.30	11.35	–0.10	1.73	6.82	0.11	1.00
vanadium	6.46	16.73	50.35	14.09	7.80	21.41	20.68	18.09	19.20
zinc	4.34	42.33	0.55	13.65	1.17	2.02	65.55	2.26	11.90
Detailed Chemistry									
antimony	0.15	1.34	0.08	0.30	0.17	2.86	0.15	0.13	0.15
arsenic	1.09	8.35	0.02	9.43	9.56	12.29	3.70	1.43	2.60
chromium (hexavalent)	–0.10	0.05	–0.02	0.02	–0.17	0.32	–0.10	0.03	–0.30
cyanide	–0.01	–0.01	–0.00	0.01	–0.01	–0.01	–0.00	–0.00	–0.01
fluoride	–0.43	–0.05	–2.58	–1.33	0.93	–0.04	–1.63	–0.13	–1.00
lead (trace)	–0.13	–0.01	–0.10	0.10	–0.10	0.02	0.00	–0.13	–0.00
mercury	0.03	0.25	0.01	0.08	0.02	0.53	0.04	0.03	0.02
selenium	0.04	–0.00	0.01	–0.01	0.02	0.00	0.01	0.00	0.03
IC Scan (anions)									
chloride	5360.00	4305.67	9.25	3167.50	7070.00	2686.75	3566.08	4926.67	121.00
nitrate	22.40	14.31	9.60	21.50	11.10	26.60	10.77	22.00	–1.00
nitrite	–1.00	–1.00	–0.53	–0.75	–1.00	–1.00	–0.76	–1.00	–1.00
sulphate	94.33	15.56	2.00	31.10	8.00	2.25	36.20	80.33	6.00
bromide	25.37	17.04	0.28	17.00	10.10	3.18	32.49	10.07	6.00
iodide	3.20	6.07	–0.08	0.67	8.65	0.10	7.48	0.87	0.20
thiocyanate	–3.37	–3.12	–2.75	–2.75	–2.10	–5.00	–1.65	–5.00	–0.10
thiosulphate	–1.33	–1.33	–0.75	1.50	–1.50	–1.00	–0.08	–1.00	–2.00
carbonate	833.00	5099.67	300.00	3350.00	849.50	11450.00	1166.33	400.00	–1.00

candidate feeds concentrated on the chemistry and environmental characteristics of the effluents to assess their suitability for re-use, secondary treatment and/or ultimate safe disposal.

The coked residual solids from individual batch pyrolysis runs were transferred to a batch combustion apparatus in which the operation of the Combustion Zone of the Processor can be simulated and the burning characteristics of the deposited coke may be studied. The operating variables studied were combustion temperature, air flow rate, and speed of rotation. The relationships among operating variables, coke combustion rates and flue gas composition were determined. Flue gases were analyzed and monitored continuously for concentrations of CO, CO_2, SO_2 and O_2 and samples of burned solids were recovered for analysis and subsequent leachate testing.

RESULTS OF PHASE I BATCH TESTING

The conclusions from the batch treatability pyrolysis and combustion tests are:

- All of the samples yielded a distillable oil with a gravity ranging from 22° API to 27°API. The corresponding yield of C_4+ liquid oil (Table 5) ranged from 75% to 90% (expressed as weight percent of the oil in the feed).
- The combusted solids are free of oil and grease.
- All of the coke deposited on the solids during pyrolysis (2–4% by weight) is consumed during combustion. In general, priority polycyclic aromatics in the combustion gases were below detection limits.
- The pyrolysis water product is sour, with high BOD and COD, and would require treatment prior to reuse or surface disposal.
- Metals and salts in the feed reported primarily to the coked solids. Apart from small quantities lost to the flue gases, metals remained with the mineral solids following combustion. Chloride concentration in the burned solids was substantially lower than in the coked solids prior to combustion of the coke.
- Leachate tests of the burned solids demonstrated that the contained metals and salts are stable, with relatively small concentrations appearing in the leachate. Table 6 compares average values of selected anions and metals found in the burned solids and the corresponding leachates.

PHASE II – CONTINUOUS FLOW PILOT PLANT RUNS

The Phase II test program involved the processing of four separate bulk samples of oily wastes obtained from the Lloydminster and Cold Lake areas. A total of 380 tonnes was processed during 230 hours of operation in the continuous flow, 4.5 tph pilot plant. The source and type of each of the four bulk samples fed to the Processor in this program are shown in Table 7.

In the pilot plant, which incorporates essentially all of the features of a commercial system, all of the feed and discharge flows were measured and sampled during 13 separate operating windows, or balance periods, of steady state operation.

With the exception of the Mobil Kitscoty field tank sand, the bulk samples were viscous fluids which were blended with a measured amount of clean sand to facilitate feeding by means of the conveyor feed system.

The average contents of oil, water and solids of each waste sample, prior to blending with clean sand, are shown in Table 7, together with the average concentrations of chlorides and sulphates. The chloride and sulphate concentrations in the blending sand were both less than 20 PPM. Complete analyses of each feed and the blending sand are shown in Table 8.

Feed and effluent streams of the ATP System (solids, liquids and gases) were sampled, generally at half hour intervals, during each operating window. Composite samples were prepared corresponding to each window. The environmental characteristics of each sample were then determined by analysis.

The main objective of the Phase II testing was the production of phase separated effluents (water, oil, gases and solids) which may be re-used, disposed directly in an environmentally acceptable manner, or further treated by conventional methods.

RESULTS OF PHASE II PILOT PLANT TESTS

OIL YIELD AND QUALITY

The yield of C_4+ oil, expressed as a weight percent of oil in the feed, ranged between 56% and 65.3%, with an average yield of 60.9% for all of the feed materials processed. The corresponding API gravity ranged from 28.4° API to 39.2° API, with an overall average of 32.5°. The yield of distillable oil was very good, and this distillate can be recycled or used as a diluent for heavier oils to assist in handling or pipeline transport.

Table 5. Pyrolysis tests data summary (data averaged per waste type)

Waste source number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	23
Process temperature (F)	1036	1019	1054	1035	1031	1058	998	1009	1026	1017	1029	1023	1027	1052	1073	997	1071
Constituents of feed (wt%)																	
Total H-C products	15.37	45.91	43.64	25.58	91.36	18.04	48.41	1.52	29.95	14.49	1.48	6.13	32.98	78.18	12.30	95.22	29.60
Water	13.11	35.14	39.79	36.02	4.32	11.06	33.94	11.70	13.31	10.95	11.80	17.08	18.14	13.17	9.73	1.34	55.60
Solids	71.53	18.95	16.58	38.40	4.33	70.90	17.65	86.79	56.74	74.56	86.72	76.78	48.88	8.65	77.97	3.45	14.80
Distribution of hydrocarbon products (wt%)																	
$CO + CO_2$ gas	1.50	1.25	1.32	1.76	0.33	2.10	0.56	1.70	2.04	2.31	13.17	5.31	0.58	0.67	3.29	0.27	2.21
C_3&-BAS (c/w $H_2 + H_2S$)	3.82	2.93	3.17	3.37	3.37	4.32	2.66	19.83	3.68	3.37	16.56	6.31	2.52	3.43	5.46	3.29	3.92
Total C_4&+	84.80	87.39	81.23	74.48	84.52	84.26	84.99	22.06	61.17	82.85	11.13	71.03	85.65	90.83	78.83	84.35	89.48
Total coke make	9.88	8.43	14.28	20.39	11.78	9.31	11.79	40.40	33.11	11.47	59.14	17.34	11.25	5.06	12.43	12.10	4.39
Product oil density (g/cc)	0.90	0.92	0.91	0.91	0.91	0.89	0.92	0.71	0.92	0.91	0.67	0.88	0.91	0.89	0.89	0.91	0.89
RCR (wt%)	1.06	1.86	1.50	1.18	1.12	1.11	1.28	0.00	0.92	1.14	0.00	0.95	1.35	1.13	0.75	1.12	1.12
API gravity	25.43	22.81	23.26	24.70	23.17	27.01	22.96	69.01	22.41	24.20	79.26	29.20	23.24	26.99	27.71	23.06	27.33
Ethylene/ethane ratio (vol)	0.73	0.63	0.60	0.67	0.41	0.76	0.52	1.13	0.63	0.79	1.15	1.03	0.55	0.80	0.68	0.58	0.98

Table 6. Phase I tests – averaged values of selected anions and metals in burned solids and burned solids leachates

Constituent	Burned solid sample (ppm)	Leachate sample from burned solids (ppm)
Calcium	1603	65.8
Nickel	21	0.04
Vanadium	8	0.03
Magnesium	552	10.3
Sodium	841	6.1
Zinc	31	0.18
Chloride	241	12
Sulphate	771	39

EFFLUENT SOLIDS

All of the solids treated and discharged from the System were producéd in three streams, in the following overall average proportions:

bulk tailings	93 wt%
flue gas cyclone fines	4.9 wt%
bag house fines	1.7 wt%
H-C cyclone fines	0.4 wt%

The solids product mix was a dry, silty sand, hydrocarbon-free, with an average organic carbon content of only 21 ppm. The concentration of residual organic carbon is a function of the degree of carbon burn-off in the Combustion Zone. The calculated averages of the analyses of each of the solids discharge streams, together with the weighted average analyses of the combined solids, are presented in Table 9. These data include the anions and cations in the mixing sand used to facilitate feeding fluid material to the Processor. While the data presented are the averages of test runs on all of the candidate feeds, it is recognized that there was variation in the chemistry of the available feeds and resulting products. Nevertheless, the average values presented are indicative of the performance of the AOSTRA Taciuk Process.

The table shows that the chlorides and sulphates are primarily contained in the flue gas particulates captured in the flue gas cyclones and baghouse. These particulates amount to less than 7% by weight of total solids discharged and could be segregated for disposal in a separate secure landfill, if these concentrations made the combined solids unsuitable for disposal in an industrial landfill.

The averaged results of leachate tests and associated analyses performed on solids from each discharge source are presented in Table 10. These leachate analyses include the contribution of the mixing sand to the concentration of anions and cations found in the leachates. Consistent results were obtained for each of the wastes processed.

In summary, the results of the analysis of leachates indicate:

- presence of phenols is minimal or not detectable.
- oil and grease not detectable.
- total carbon (organic and inorganic) is low.
- heavy metals are low or not detectable.
- the average concentrations of chloride and sulphate ions in the leachates from combined solids are less than the permissible maximums for potable water. Higher than permissible concentrations are found in leachates from the baghouse solids but this is a small quantity which could either be segregated for disposal in a secure landfill or blended with bulk tailings sand.

Table 7. Composition of wastes tested in Phase II

No.	Waste source & type	Constituents (wt%)			Anion concentrations chloride	sulphate
		oil	water	solids	(ppm)	(ppm)
19	Celtic desand	15	16	69	1145	260
20	Kitscoty field tank	6	6–8	86–88	2490	612
21	Wolf Lake desand	20–30	40	30–40	355	886
22	Cold Lake desand	18–25	15–25	50–67	338	125

Notes: Constituent analyses are prior to the addition of blending sand.

Table 8. Phase II: Pilot plant runs – analysis comparison of feedstocks

Waste Source Number		19	19	19	20	20	20	21	22	22	19	21	
Processor Run		871111	880119	880211	871111	880211	880218	880119	880302	880302	880302	Clean	
Run Window		30	20/30	20	20	30	20	50	40	20/2nd	30/3rd	40/4th	
Plant Stream		101	101	101	101	101	101	101	101	101	101	101	Sand
Chemex Lab No.		1245-11	1522-4	1696-1	1245-4	1696-2	1696-1	1522-6	1522-5	49-1	49-2	49-3	Used For 1341-1
Gross Physical And Chemical Characteristics													
material density		1.124	1.315	—	0.808	—	—	11.474	1.345	—	—	—	—
wt% oil		7.5	10.7	9.13	6	5.74	5.73	14.3	9.2	8.6	9.1	6.6	—
wt% water		8	5.5	8.39	6.4	8.25	6.36	2.2	3.	5.9	8.4	4.8	—
wt% solids		84.1	83.8	81.5	86.7	85.5	86..5	83.5	87.8	84.6	82.4	88	—
wt% sulphur		0.34	0.37	0.29	0.6	0.11	0.21	0.51	0.57	0.62	0.43	0.41	—
Indicator Chemistry	(values in ppm)												
ICP scan for metals	aluminum	1330	905	1240	1020	870	950	2590	2160	2070	1273	3310	1750
	barium	69.8	55.1	50	173	64	124	133	122	62.8	52	94.7	73.3
	beryllium	0.1	0.1	0.1	–0.1	–0.1	0.4	0.1	0.1	–0.1	–0.1	0.1	0.1
	boron	6.4	8	23.6	4.7	19.5	6.5	13.7	15.8	6.9	6.9	15.1	8.2
	cadmium	–0.1	–0.1	–0.1	–0.1	–0.1	–0.1	–0.1	–0.1	–0.1	–0.1	–0.1	–0.1
	calcium	26000	11000	13900	4870	4840	7300	47800	30200	27500	16700	31200	51200
	chromium	3.5	1.6	3.4	2.1	1.7	2	7.6	5.1	4.1	1.3	6.9	3
	cobalt	2.5	4.7	2.4	5.8	2.7	1	5.6	4	1.7	2.6	2.2	3.2
	copper	5.8	6.5	6	2.6	3.9	3.6	18.2	16.2	17.5	5.6	13.6	4.7
	iron	4890	3300	4380	3100	3200	2600	8300	8090	4140	3900	7310	6200
	lead	6.6	5.3	6.18	16.7	4.3	6.16	4.6	4.5	17.1	18.7	18.2	8.3
	lithium	3.5	1.3	2.1	3	2.1	1.8	3.7	3.4	1.6	2.82	2.8	
	magnesium	3770	3320	1600	842	920	1170	5630	4370	5960	2100	4480	6700
	manganese	174	220	169	82.8	115	82.2	214	160	192	203	176	183
	molybdenum	5.7	3.2	3.8	6.3	2.5	3.1	9.7	8.4	6.2	4.1	10.9	7.3
	nickel	12.9	11.9	11.2	14.9	7	6.8	16.1	15.8	13.4	8.5	13.1	8.2
	potassium	219	192	223	190	195	217	315	310	560	390	830	160
	silicon	132	165	76	95.8	45.6	110	283	463	30.4	52.6	140	203
	sodium	1030	980	1040	1570	2060	1370	680	550	590	1070	670	83.9
	strontium	47.9	31.8	37	47.1	42.2	42.3	72.5	43.7	34.7	38.09	64.6	43.2
	titanium	20.6	25.8	30.2	18.5	14.6	17.1	53.4	53.6	3.8	22	62.9	3.6
	vanadium	14.6	14.1	14.4	10.5	10	9.2	25.9	25.9	9.4	13.6	26	5.9
	zinc	29.6	21.8	25	28.2	18.8	18.3	362	42.9	44.4	22.2	145	19
IC scan													
chloride		1200	1020	990	2340	3200	1930	273	184	491	1370	437	10
nitrate		–1	–0.5	0.6	–1	2.3	1.2	–0.5	–0.5	–0.5	–0.5	–0.5	0.9
nitrite		–1	–0.5	–0.1	–1	–0.1	–0.1	–0.5	–0.5	–0.5	–0.5	–0.5	–0.1
sulphate		319	238	183	486	640	710	473	42	207	302	1300	17
IC scan													
bromide		6.6	6.6	—	15	—	—	0.7	1.5	—	—	—	
iodide		–0.1	–0.1	—	–0.1	—	—	–0.1	–0.1	—	—	—	
thiocyanate		–1	–1	—	—	–1	–1	—	—	—	—	—	
thiosulphate		–0.5	–0.5	—	–0.5	—	—	–0.5	9.7	—	—	—	

Table 9. Phase II processor runs: solids products samples analysis data – average values for solids products

		Tails comp	Flue–cy fines	Bagh'se fines	HC–CYC fines	Product mixture
General characteristics						
Total organic carbon (ppm)		18.3	33	140	0	21.2
Total inorganic carbon (ppm)		29.5	30	35	0	29.6
Total carbon (ppm)		47.8	63	175	0	50.8
Phenols (ppm)		0.0	0	-	0.012	
Indicator chemistry (ppm)						
ICP scan	aluminum	4334.1	11055.4	35956.3	7468.3	5224.0
	barium	120.6	257.0	205.2	181.6	128.6
	beryllium	0.2	0.3	1.2	0.3	0.2
	boron	13.7	32.6	73.4	23.8	15.7
	cadmium	–0.1	1.1	0.1	0.4	–0.040
	calcium	28147.8	27440.0	51724.0	24451.4	28539.6
	chromium	26.6	19.0	45.2	14.6	26.5
	cobalt	3.1	9.2	17.0	6.3	3.6
	copper	7.7	30.6	48.2	29.0	9.5
	iron	7326.5	12819.7	26139.9	11832.3	7927.1
	lead	6.5	37.6	29.1	19.4	8.4
	lithium	2.9	8.0	14.4	4.2	3.4
	magnesium	3876.2	6844.0	10765.8	5167.3	4141.7
	manganese	215.5	280.5	552.4	232.2	224.6
	molybdenum	12.7	32.4	88.5	20.5	15.0
	nickel	12.4	29.9	70.1	21.1	14.2
	potassium	929.5	1735.2	4465.4	1097.1	1031.6
	silicon	253.7	572.7	1176.1	788.3	285.5
	sodium	761.7	1318.7	6353.2	1214.1	889.0
	strontium	51.6	112.3	323.2	101.2	59.4
	titanium	48.5	140.8	196.7	86.8	55.5
	vanadium	20.2	50.4	116.6	35.5	23.3
	zinc	72.3	165.3	302.7	115.2	80.8
IC Scan for major anions (ppm)						
	chloride	470.6	4819.6	8870.0	1304.0	829.2
	nitrate	–0.5	–0.7	3.5	–1.2	–0.4
	nitrite	–0.5	–0.7	–0.7	–1.2	–0.5
	sulphate	1042.0	5898.8	11902.0	2821.4	1469.1

In general, it was concluded that the combined solids produced in pilot plant tests would be suitable for disposal directly as a Class 3 industrial landfill.

EFFLUENT WATERS

The averaged analyses of the Preheat Zone Vent waters and the sour process water drained from the oil fractionator overhead accumulator are shown in Table 11.

These waters showed high concentrations of phenol, BOD, COD and sulphur, and are similar to process waters generated in refinery operations involving thermal cracking of high sulphur, heavy oils and residues. Such waters would need to be treated if reuse or discharge to surface water was contemplated. Otherwise, disposal to deep well would be preferred.

GASEOUS EMISSIONS

Off-gas (non-condensable gases in the hydrocarbon vapor stream) was flared in these pilot plant tests. In commercial operations, off-gas would be used as fuel for the Processor auxiliary burners, depending on sulphur content of oil in the feed.

Flue gases generated by the combustion of coke

Table 10. Phase II processor runs: leachates samples analysis data

Plant stream Sample		Average values from all runs				Values proportioned per flow quantity				
		111 Tails leachate	200 Tails comp leachate	130 Flue cyc leachate	138 Baghouse leachate	111 Tails leachate	200 Tails comp leachate	130 Flue cyc leachate	138 Baghouse leachate	Avg all leachate total product
General characteristics										
oil and grease (ppm)		-0.26	-0.5	-0.2	-0.2	-0.24	-0.50	-0.01	-0.00	-0.75
total suspended solids (ppm)										
pH										
total organic carbon (ppm)										
total inorganic carbon (ppm)										
total carbon (ppm)										
phenols (ppm)		0.0092	0.004	0.0185	0.088375	0.01	0.00	0.00	0.00	0.01
Indicator chemistry (values in ppm)										
ICP scan for metals	aluminum	2.760	3.292	4.475	7.562	2.58	.29	0.21	0.14	6.08
	barium	0.210	0.256	0.138	0.111	0.20	0.26	0.01	0.00	0.46
	beryllium	-0.001	0.001	0.000	0.002	-0.00	0.00	0.00	0.00	0.00
	boron	0.149	0.232	0.918	3.078	0.14	0.23	0.04	0.06	0.41
	cadmium	0.002	0.001	0.003	0.005	0.00	0.00	0.00	0.00	0.00
	calcium	871.667	1176.000	1237.500	2070.000	814.40	1176.00	58.99	37.26	2049.39
	chromium	0.002	0.001	0.002	0.011	0.00	0.00	0.00	0.00	
	cobalt	0.003	0.006	0.035	0.050	0.00	0.01	0.00	0.00	0.01
	copper	0.028	0.045	0.034	0.056	0.03	0.05	0.00	0.00	0.07
	iron	0.917	0.810	0.355	0.736	0.86	0.81	0.02	0.01	1.68
	lead	0.000	0.020	0.005	0.001	0.00	0.02	0.00	0.00	0.02
	lithium	0.005	0.012	0.050	0.093	0.00	0.01	0.00	0.00	0.02
	magnesium	80.778	120.320	137.250	190.400	75.47	120.32	6.54	3.43	202.33
	manganese	2.431	3.524	4.515	41.974	2.27	3.52	0.22	0.76	6.01
	molybdenum	0.060	0.078	0.138	0.360	0.06	0.08	0.01	0.01	0.14
	nickel	0.023	0.034	0.125	0.207	0.02	0.03	0.01	0.00	0.06
	potassium	3.671	7.056	10.598	29.260	3.43	7.06	0.51	0.53	10.99
	silicon	19.978	23.240	51.400	81.800	18.67	23.24	2.45	1.47	44.36
	sodium	11.869	9.246	26.300	111.770	11.09	9.25	1.25	2.01	21.59
	strontium	1.043	1.458	3.948	8.434	0.97	1.46	0.19	0.15	2.62
	titanium	-0.001	-0.001	-0.001	-0.001	-0.00	-0.00	-0.00	-0.00	-0.00
	vanadium	0.024	0.017	0.030	0.107	0.02	0.02	0.00	0.00	0.04
	zinc	0.613	1.504	3.405	0.712	0.57	1.50	0.16	0.01	2.24
IC scan for major anions (ppm)										
chloride		81.356	29.080	93.475	484.300	76.01	29.08	4.46	8.72	109.55
nitrate		-0.066	-0.035	-0.031	0.189	-0.06	-0.04	-0.00	0.00	-0.10
nitrite		-0.072	-0.035	-0.031	-0.140	-0.07	-0.04	-0.00	-0.00	-0.10
sulphate		86.844	55.920	155.750	560.800	81.14	55.92	7.42	10.09	144.48
IC scan for minor anions (ppm)										
bromide		1.292	0.260	0.630	2.698	1.21	0.26	0.03	0.05	1.50
iodide		0.046	0.010	0.020	0.151	0.04	0.01	0.00	0.00	0.05
thiocyanate		-0.050	-0.050	0.000	0.013	-0.05	-0.05	0.00	0.00	-0.10
thiosulphate		0.977	0.875	0.815	3.115	0.91	0.88	0.04	0.06	1.83

Table 11. Phase II processor runs: water products analysis data

		Average values for waters		
		Preheat water	Sour water	Stripped sour H_2O
oil and grease (ppm)		184.3	798.9	188.5
total suspended solids (ppm)		169.8	295.9	24.5
pH		6.1	2.9	4.6
total organic carbon (ppm)		243.7	5404.4	2650.0
total inorganic carbon (ppm)		−1.3	−4.0	−5.0
total carbon (ppm)		245.2	5404.2	2650.0
phenols (ppm)		6.7	426.0	312.5
Water treatability				
COD		1644.0	18621.1	8605.0
BOD		410.0	3880.8	3110.0
Turbidity		1235.3	361.1	270.0
SiO_2		10.9	6.6	10.0
NH_3–N		16.6	408.3	261.0
Total alkalinity		57.5	63.4	24.5
Free NH_3–N		0.031	−0.004	0.000
Total Kjeldhal nitrogen		25.2	545.1	250.0
Total sulphur		620.2	1653.9	1087.0
Metals and major anion (values in ppm)				
ICP scan for materials	aluminum	1.63	2.2	0.2
	barium	0.13	0.1	0.2
	beryllium	0.000	0.000	−0.001
	boron	0.28	0.3	0.6
	cadmium	0.003	−0.001	−0.001
	calcium	720.00	17.1	81.8
	chromium	0.02	0.2	−0.001
	cobalt	0.03	0.009	0.008
	copper	0.12	1.4	−0.001
	iron	8.18	50.5	372.5
	lead	0.14	0.1	0.040
	lithium	0.03	0.001	−0.001
	magnesium	17.20	2.0	1.9
	manganese	1.33	0.5	3.1
	molybdenum	0.12	0.010	0.001
	nickel	0.06	0.4	0.1
	potassium	2.32	1.7	0.6
	silicon	4.40	3.9	4.7
	sodium	9.78	8.4	0.7
	strontium	1.59	0.1	0.4
	titanium	0.02	0.016	−0.001
	vanadium	0.03	0.024	0.011
	zinc	0.11	7.2	1.2
IC scan for major anions (values in ppm)				
chloride		68.71	364.3	136.0
nitrate		0.06	4.4	0.2
nitrite		0.08	−0.1	0.1
sulphate		1573.64	123.2	36.3

deposited on spent solids and supplemental fuel did not contain appreciable concentrations of SO_2, NO_x, H_2S and particulates after treatment in the flue gas clean-up circuit. Flue gas discharged from the stack was considered to meet the regulatory requirements of the Alberta Clean Air Act.

CONCLUSIONS OF THE TEST WORK AND PROGRAM

This two phase program is considered an extensive examination of the AOSTRA Taciuk Process technology for the treatment of oil field wastes. The results of the process testing and environmental analysis confirm that the technology can be applied to the recycling and disposal of oily waste in an environmentally acceptable manner. The Processor extracts all of the oil from the feed and recovers most of the oil (up to 70%) as a by-product, which can be reused, sold, or possibly used as a diluent. The Processor also generates separate product streams of dry solids, water and flue gas emissions. Each of these is easier to handle for re-use or disposal than when as combined with the original waste.

The data generated through this program are sufficient for evaluation and scale up to a prototype commercial production treatment plant. It was also found that the design and development of a demonstration treatment plant could achieve better performance than the Pilot Plant to meet current regulatory requirements and provide improved process efficiencies. These improvements include heat or energy savings, and optimization of various effluent streams.

SUMMARY

The ATP System pyrolysis technology offers a number of unique features for consideration of its use in treating various oily, organic wastes. They include the following:

- the process has the intermediate step of extracting the hydrocarbons (oil) from the solids, which presents them as available for re-use or refining, rather than destruction.
- treatment plants can be supplied for large throughput capacity, to 20 tph or greater.
- low unit costs of plant operation, particularly for the larger capacity plants.
- all of the treatment process steps for extraction of the contaminants are confined to a single process vessel.
- the Process operates at low to intermediate temperatures (to 600°C), which enhances safety and indicates low energy requirement.
- water and oil contaminants are recovered as separate products, which makes them available for secondary treatment, re-use or separate disposal.
- solids products are hydrocarbon-free, and can usually meet leachate criteria for direct disposal.
- heat make up uses Process by-products as fuel.
- combustion conditions include low gas velocity, long residence time for the fuels, and extensive turbulence and mixing in the combustion zone. This assists combustion completion and control of the gas emissions.
- the System has been extensively tested and shows capability to operate with stability and safety on widely varying wastes.

Much interest has been expressed by industry and regulatory representatives in the AOSTRA Taciuk Process System, particularly since the first commercial waste treatment plant became available and was purchased by Soiltech, Inc. The ATP pyrolysis technology can address a broad field of applications for treating hazardous and non-hazardous industrial wastes. It offers fast clean up capability combined with the recovery and reuse of the contaminants, while operating within the stringent emission standards required in today's modern world.

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RECENT ADVANCES IN THE TREATMENT OF WATER FROM IN-SITU HEAVY OIL RECOVERY

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INTRODUCTION

The in-situ recovery of heavy oil in Canada by the steam injection method generally produces two to twenty times as much water as oil.[1] This water, commonly called "produced water," is currently disposed of either by recycle to the oil-field steam generators or through injection into a suitable underground formation. Although the Canadian oil industry has attempted to recycle the produced water wherever the circumstances would permit, there are several factors which make produced water recycling unattractive at some locations.

Over the last decade, the oil industry and government agencies in Canada have made significant financial commitments to research related to the evaluation and development of technologies which will resolve the problem associated with the recycle of produced water. This research has included detailed characterization of produced water, bench scale tests, off-site pilot scale test and on-site pilot scale tests. The research has been conducted by individual oil companies, equipment suppliers, and government research laboratories. As well, there have been studies that were funded jointly by the oil industry and government agencies.

The research on produced water treatment conducted in Canada over the last decade has concentrated on three parameters; (1) oil and suspended solids, (2) silica, and (3) total dissolved solids. This paper provides a summary of the work conducted in these area, and reviews the status of the research and development currently ongoing in Canada on produced water treatment.

PRODUCED WATER FROM THE IN-SITU RECOVERY OF HEAVY OIL

Currently, two techniques are being used in Canada for the commercial recovery of heavy oil from the tar sands and heavy oil deposits. One of thee techniques involves the surface mining of the tar sands and the recovery of the heavy oil through the processing of thee sand in surface treatment facilities. The other technique involves the injection of steam into the oil bearing formation, thereby reducing the velocity of the oil to a level where it is possible to pump the oil to the surface. This latter technique is commonly referred to as "in-situ" heavy oil recovery. Although the in-situ heavy oil recovery technique is still in the experimental stage, a few commercial plants are now using this technique to produce heavy oil from the deposits in Western Canada.

The fluid produced by the in-situ heavy oil recovery technique is usually a mixture of oil, sand and water. The water-to-oil ratio in this fluid is quite variable depending on many factors including the geology of the deposit, the age distribution of the producing wells, and communication between the steam-injection and oil-production wells. In most cases, however, the water-to-oil ratio in the produced fluid is in the range of 2 to 20 (by volume).[1] The produced fluid is proceed to separate the and and water from the oil, and to prepare the oil for shipment. The produced water is then treated to make it amenable to either; (1) disposal through deep-well injection into a suitable underground formation, or (2) recycle to oil-field team generators for producing the team needed for in-situ heavy oil recovery well. Figure 1 is a simplified schematic of a typical Canadian in-situ heavy oil recovery operation, and how the source of produced water at such an operation.

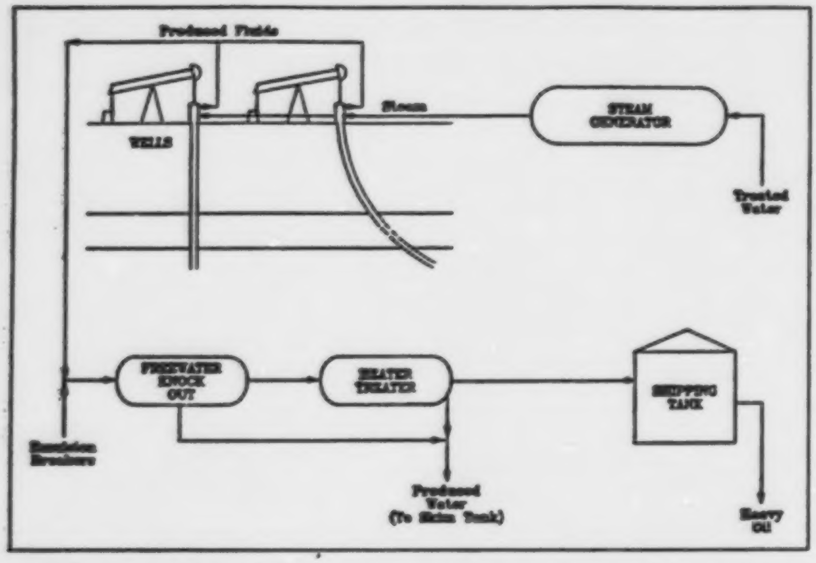


Figure 1. Schematic of a typical Canadian in-situ heavy oil recovery operation.

CONVENTIONAL PROCESSES FOR PRODUCED WATER TREATMENT

The complexity of the processes train required to treat the produced water depend on the quality of the water and its ultimate fate (deep-well disposal versus recycle to steam generators). For recycle to the oil-field steam generator, it is generally believed1 that the water has to be treated to meet the specification shown in Table 1. For disposal through deep-well injection, there are no general specification. However, excessive free oil and suspended solids are considered undesirable. Also, the compatibility of the injected water with the formation water in term of ionic composition is generally evaluated to enure that the risk of formation plugging is minimized.

Table 2 show the the characteristic of produced waters generated at in-situ heavy oil recovery operation in various heavy oil regions of Western Canada. Generally these water do not meet the specification shown in Table 1 with respect to oil, suspended solids and hardness. Also, at come location, the concentration of total dissolved solid (TDS) and silica is higher than the specification shown in Table 1.

Figure 2 shows a schematic of a typical process train used in Canada for the treatment of produced water at those in-situ heavy oil recovery operations which recycle produced water to the oil-field steam generator. The process train involve the removal of oil and suspended solid, hardness and silica. Where the concentration of TDS does not meet the specifications, the produced water

Table 1. Feedwater quality specifications for oilfield steam generators

Parameter	Concentration (mg/L)
Total hardness as $CaCO_3$	<0.5
Silica, as SiO_2	<50
Oil	<1
Total dissolved solids	<8000
Total suspended solids	0
Dissolved oxygen	<0.04
Iron	<0.05

Table 2. Produced water characteristics at various heavy oil regions in Canada[2]

Parameter (mg/L)	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6	Site 7
Total dissolved solids	3240	5450	6730	35900	48700	68500	16700
Total hardness as $CaCO_3$	210	78	370	5510	3240	4230	1240
Silica as SiO_2	NA	NA	NA	NA	40	20	150
Total suspended solids	50	150	170	1038	330	230	77
Oil and grease	80	170	40	480	140	450	150
Iron	0.13	0.43	0.65	17	0.75	3.9	0.68
Dissolved organic carbon	320	110	130	140	250	130	290

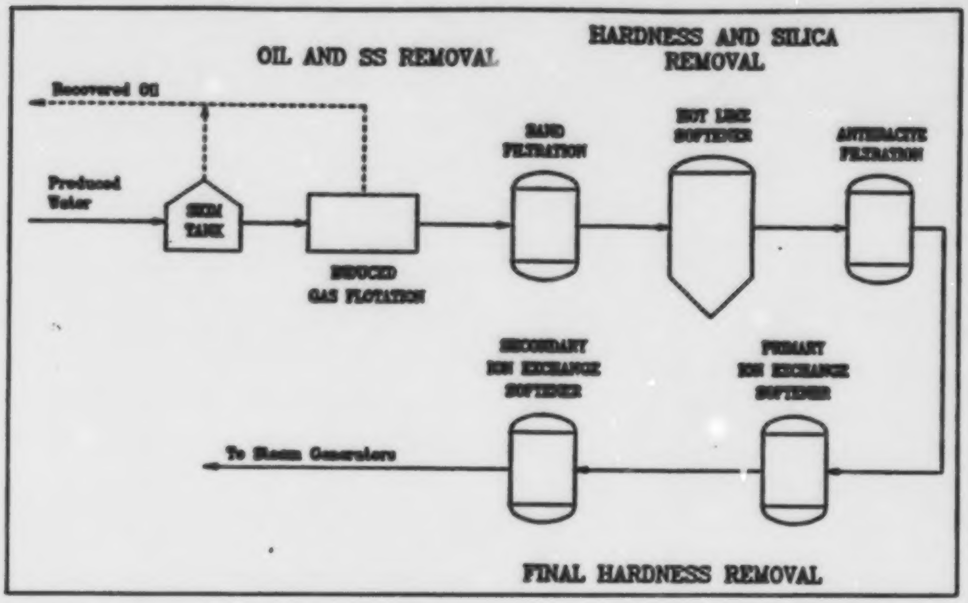


Figure 2. Schematic of typical produced water treatment at in-situ heavy oil recovery operations in Western Canada.

is either not recycled, or diluted with low TDS water before it is recycled. As shown in Figure 2, suspended oil is generally removed through a combination of skim tanks, induced gas flotation unit (IGF), and granular media filters (GMF) in series. Hardness is removed using either a combination of lime softening and cation exchange or cation exchange alone depending on the concentration of hardness in the untreated water. If silica is present at unacceptable concentrations, it is removed through hot or warm lime softening along with the bulk of the hardness.

RECENT DEVELOPMENTS IN PRODUCED WATER TREATMENT

Four full-scale treatment plants have been built in Canada to recycle produced water to the steam generators. These plants are generally able to meet the requirements for the recycle of produced water. However, improvements to the existing technology and development/demonstration of alternative technologies are required to enhance the performance and reliability of the produced water treatment systems. Therefore, research and development (R&D) work has continued in Canada to further improve the ability to recycle the produced water. The focus of the produced water treatment R&D work in Canada has been on three parameters; (1) oil and suspended solids, (2) silica, and (3) TDS.

Oil and Suspended Solids Removal

A shown in Figure 2, the conventional process train for removing suspended oil from produced water uses IGF in eries with GMF as the final polishing step. A variety of granular media such as sand, granite, anthracite and crushed walnut shells are used in these filters depending on the preference of a particular designer. While this approach ha become well-entrenched among the practising engineers, the nature of oil in produced waters from in-situ heavy oil recovery causes difficulty in achieving the desired technical and cost performance from these filters. Also, the conventional process train (comprising of IGF and GMF) is not able to satisfactorily handle the oil lugs which occur quite frequently at the in-situ heavy oil sites. Therefore, work has continued in Canada to improve the performance of the granular media filters and to evaluate alternative processes for achieving the desired oil removal in a more cost-effective and consistent manner than is currently possible. Major studies which have been conducted in this respect over the last several years include; (1) optimization of granular media filter, (2) evaluation of one commercial brand of ceramic cross-flow microfilter, (3) development and testing of polymeric cross-flow ultrafiltration membranes specifically designed for this application, and (4) testing of a commercial liquid-liquid hydrocyclone.

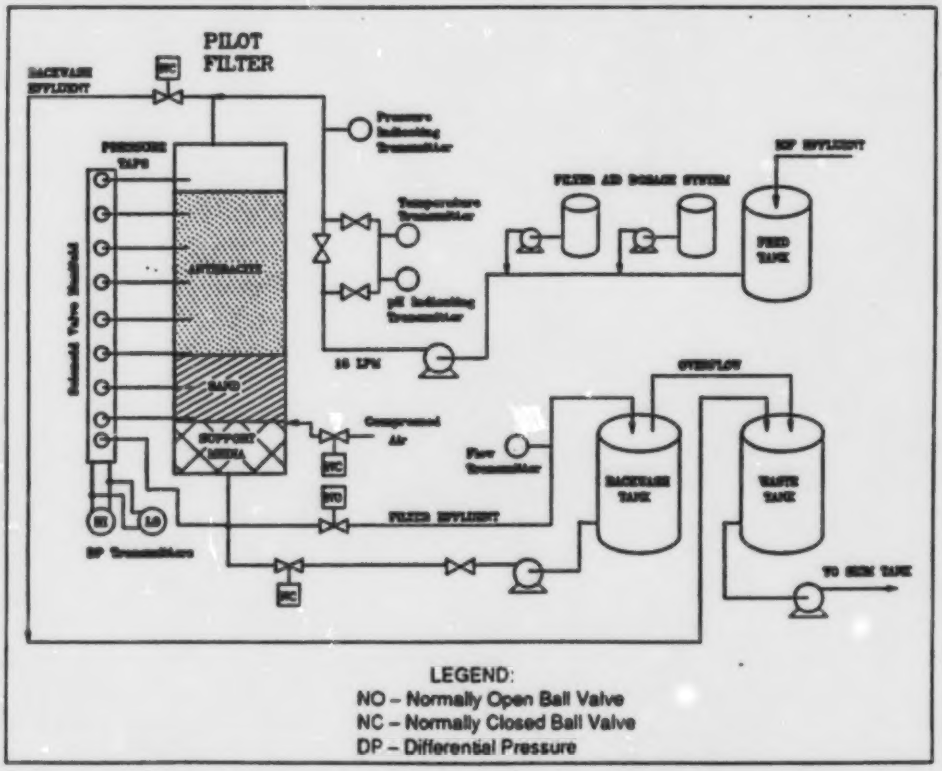
Optimization of Granular Media Filters

All full-scale produced water treatment facilities in Canada use GMF for removing fine oil and suspended solids from the produced water. Although GMF have been traditionally used for other oily wastewaters, some of the design parameters and the effect of operating conditions on the performance of GMF in treating produced water are poorly understood.

From 1985 to 1988, Environment Canada's Wastewater Technology Centre (WTC) conducted a study[3,4] to; (1) investigate the effects of the typical operating conditions used at produced water treatment facilities on GMF performance, (2) to modify/optimize these conditions to improve the GMF performance, and (3) to develop a fully instrumented system for process control. The study consisted of in-house and field pilot filtration tests using synthetic (for the in-house work) and actual produced water under field conditions. Figure 3 shows a schematic of the pilot filter unit which was used in the field. The unit was instrumented to collect pressure drop readings throughout the bed and received effluents from an IGF unit which was expected to remove the bulk of the oil before final polishing in the GMF.

The main conclusions of the study were that; (1) chemical addition would be necessary to ensure a fairly consistent effluent quality, (2) most of the filtration was occurring in the first 10 cm of the filter bed, and (3) dual media filtration would be better than single media filtration. The key recommendations were; (1) operate at higher hydraulic loadings (7.7 L/(m^2·s)) than the conventional loadings (0.8–1.0 L/(m^2·s)), (2) use a maximum media depth of 1 m, (3) use chemicals to enhance particle capture onto the media, and (4) increase the intensity of backwashing. Based on the insights gained in the study, an optimized GMF design was developed. This design is compared with the conventional design in Table 3.

In addition to the work by the WTC, the oil industry has tested commercial filters of various deign. One of thee is an deep-bed filter marketed by the Hydromation Company which uses crushed walnut shells as the filter media and on a periodic basis, intense media cleaning in a scrubber attachment to enhance the performance.[5] The other


PILOT
FILTER
BACKWASH EFFLUENT
NC
Pressure Indicating Transmitter
PRESSURE TAPS
Solenoid Valve Manifold
ANTHRACITE
SAND
SUPPORT MEDIA
Temperature Transmitter
pH Indicating Transmitter
FILTER AID DOSAGE SYSTEM
IGF EFFLUENT
FEED TANK
OVERFLOW
Compressed Air
NC
NO
Flow Transmitter
FILTER EFFLUENT
BACKWASH TANK
WASTE TANK
HI
LO
DP Transmitters
NC
TO SKIM TANK

LEGEND:
NO – Normally Open Ball Valve
NC – Normally Closed Ball Valve
DP – Differential Pressure

Figure 3. Schematic of WTC pilot filter unit.

Table 3. Comparison of optimized and conventional GMF designs

	Optimum pilot scale		Conventional full scale
Filter design parameters:			
Media type/size	Anthracite	2.04 mm dia.	Sand 0.5 mm dia.
	Sand	1.0 mm dia.	
Media depth	Anthracite	0.75 m	1.0–1.5 m
	Sand	0.25 m	
Pressure	172 kPa	100 kPa	
Filter operating parameters:			
Filtration rate	7.7 $L/m^2 \cdot s$	0.8–1.0 $L/m^2 \cdot s$	
Design run length	24 h	24 h	
Filter surface area[1]	11.3 m^2	96.5 m^2	
Chemical filter aids[2]	Ferric chloride:	1 mg/L	None
	D6400 polymer:	10 mg/L	
Backwash procedure:			
Description	6 cycles of: (1) air scour – 2 min (3.8 $L/(m^2 \cdot s)$) (2) low-rise rinse – 4 min (4.9 $L/(m^2 \cdot s)$)		High-rise, low-rise rinses (at least 2 cycles)
Duration	38 min	approx. 30 min.	
Backwash water required	1.1% of filtered volume (24 h run length)	2–3% of filtered volume (24 h run length)	
Chemical backwash aids	Periodic solvent/surfactant rinse		Periodic solvent/surfactant rinse

Notes: [1] 7500 m^3/day treated water [2] influent oil concentration of 30 mg/L

filter design tested in Canada is the so-called "coalescing filter" which uses hydrophobic media to enhance the coalescence of oil droplet into a separable size.[6] Generally, the tests conducted by the oil industry have been in collaboration with the equipment vendors and have focused on site-specific problems. Also, data from these tests have generally not been published in the open literature. Overall, the test on various designs of GMF show that no one design offers substantial cot or performance advantage over the others[7] and alternative technologies will have to be developed if substantial improvements are required.

Evaluation of Alternative Processes for Oil Removal

As previously mentioned, the main problems of the conventional oil removal systems (IGF and GMF) include; (1) the inability to handle lugs of oil and (2) inconsistent effluent quality. One of the oil removal technologies which offers a potential for resolving these problems is "membrane technology". The other, which has attracted a lot of attention over the last several years, is the "liquid-liquid hydrocyclone".

Membrane technology. Significant recent improvements in the commercially available membranes have led to a high degree of interest in the use of membrane processes for oil and suspended solids removal. Specifically, cross-flow ultrafiltration (UF) and microfiltration (MF) are the two membrane processes most suitable for oil and suspended solids removal from produced water.

Figure 4 shows schematic of the principle of operation of cross-flow UF and MF. The feed containing oil and suspended solids flows axially in a porous tube while the clean water flows radially through the tube walls. MF implies tube wall pores in the range of 0.1 micron to a few microns. UF, on the other hand, implies much finer pores (<0.01 m). Because of the positive barrier available for separating the oil from the water, the effluents generated by UF and MF processes are expected to be consistently free of suspended oil. The flux (flow rate per unit membrane area) is generally higher for MF than for UF; however, MF can be more susceptible to particulate fouling than UF.

UF and MF membranes are made from a variety of organic polymers or inorganic materials, including

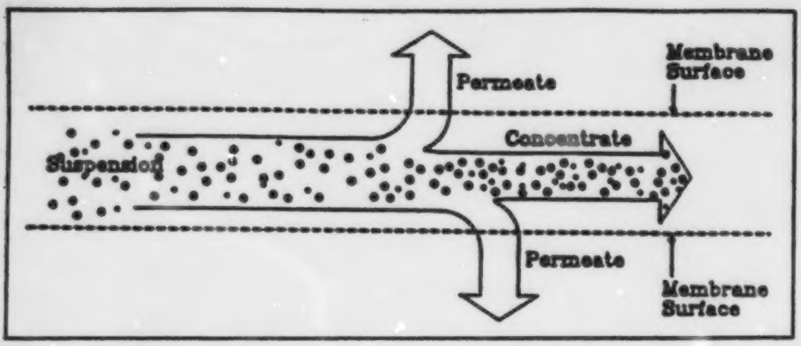


Figure 4. Schematic of principle of operation of cross-flow UF and MF.

cellulose acetate, cellulose triacetate, polysulphone, polypropylene, polymide, alumina, zirconium oxide, titanium oxide, stainless steel, glass and carbon, etc. Also the commercial membranes are available in several sizes and configurations including flat sheets, tubes, etc. For treatment of produced water, only tubular membranes have been tested in Canada. These membranes are available as modules which are made by placing several tubes in a bundle to provide high surface area per unit volume. A typical treatment system, as shown in Figure 5, consists of several of these module, a recirculation pump and ancillary tanks for feed, concentrate and product.

The work on UF for oil and suspended solids removal from produced water from in-situ heavy oil recovery-operations has consisted of off-site and on-site trials at bench and pilot scale.[8,9,10] These tests were conducted with various UF membranes developed by ZENON Environmental Systems, Burlington, Ontario. The short term tests (several days to one month) indicated that a product water flux ranging from 50–250 L/(m^2·h) could be achieved with cleaning intervals ranging from 1 to 7 days. However, during longer term pilot tests[10] (total of 11 months) conducted in 1989/90, substantially lower fluxes were attained.

MF work on produced water from in-situ heavy oil operations has been conducted at both bench and pilot scale, and off-site at research facilities as well as in the field. Most of the tests have been short term[11,12] (a few days to a few weeks) although in a recent study,[13] the field tests continued for approximately five months. All these tests have been conducted on ceramic membranes made by Alcoa, U.S.A., using a system developed by Separ Systems and Research Ltd., Calgary, Alberta. In this system, backpulsing is used to minimize flux decline, and chemicals (such as ferric chloride, calcium oxide and sodium carbonate) are added to avoid irreversible membrane fouling. Available data from one of the short term tests indicate flux ranging from 800–1800 L/(m^2·h).[11] In the longer term pilot tests,[13] the stable flux was substantially less than what was observed previously in the short term trials. Also, no substantial difference in the flux rate was observed between tests conducted with and without the use of chemical addition during the longer term trials.

Studies of membrane technology for produced water treatment have identified several difficulties such as unacceptably low flux, occasional degradation of permeate quality and high frequency of cleaning. However, it must be recognized that the work completed to date has been limited both in terms of scope and duration. There are many membrane

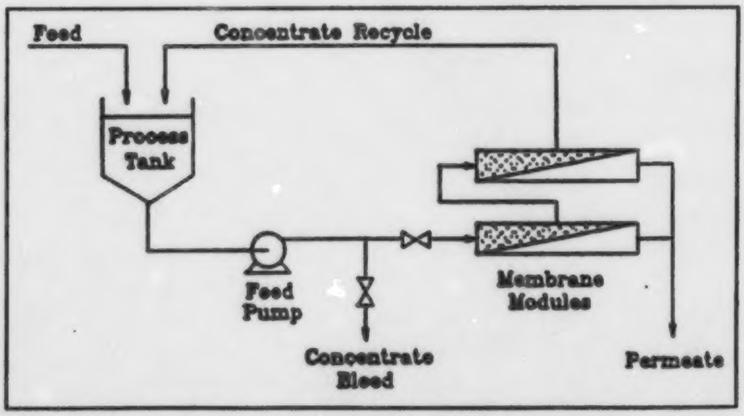


Figure 5. A typical treatment system for UF and MF.

materials and systems currently available that are potentially suitable for application to produced water. In addition, longer term testing is required to determine the performance of membrane processes under the range of conditions seen over time at operating oil-field sites. There are plans[14] to initiate a major industry-government joint study in 1991, on a systematic evaluation of several commercial and experimental membranes for the removal of oil and suspended solids from produced water in Western Canada. The study is expected to include extensive long-term (1 year) bench-scale field tests of up to 20 membranes to identify the best membrane(s) for this particular application. Later in the study, the best membrane(s) will be evaluated at pilot-scale in long-term field trials to obtain operating and maintenance cost data. Following these tests, a semi-commercial demonstration plant may be built under the study.

Liquid-liquid hydrocyclone. Another process being tested in Canada for oil removal from produced water is the liquid-liquid hydrocyclone. This process make use of a swirling flow to generate centrifugal forces which separate the oil and water based on their density difference. Hydrocyclones have the potential to replace the skim tank and IGF, and improve the oil removal efficiency due to the fact that; (1) they can handle a high degree of variation of oil in the influent, and (2) the high temperature and high pressures of the produced fluids can be advantageous.

There are two types of commercially available hydrocyclones; (1) static and (2) rotary. In the static hydrocyclone, the swirling flow is established by high inlet flow and pressure; in the rotary hydrocyclone, mechanical rotation provides the swirling flow motion. Figures 6 and 7 show schematics of the two types of hydrocyclones.

Currently, hydrocyclone applications are limited to the treatment of offshore produced water, and full-scale static hydrocyclone systems have been installed at more than 50 offshore platforms.[15] One rotary hydrocyclone system is being installed offshore in Holland.[16] The static hydrocyclone is now marketed by Conoco Special Products Inc. (CSPI) in the U.S. The rotary hydrocyclone, which is a relatively newer technology, is being marketed by Serck Baker U.K. under the name "Dynaclean". Performance data for the static[17] and the rotary[18] hydrocyclones indicate that the target oil concentrations (40 mg/L) required for discharge of the offshore produced water to the sea can generally be achieved with this technology.

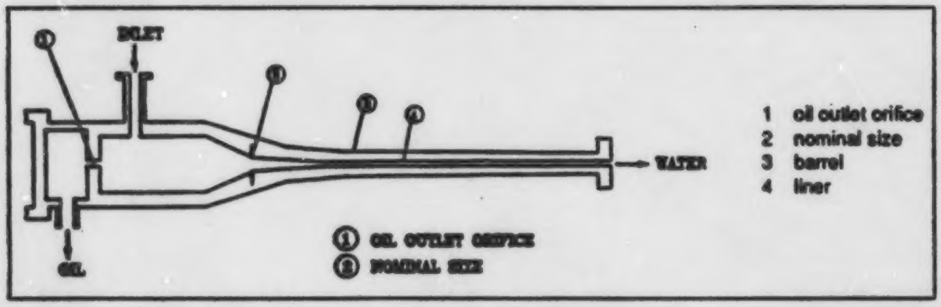


Figure 6. Schematic of the static hydrocyclone.

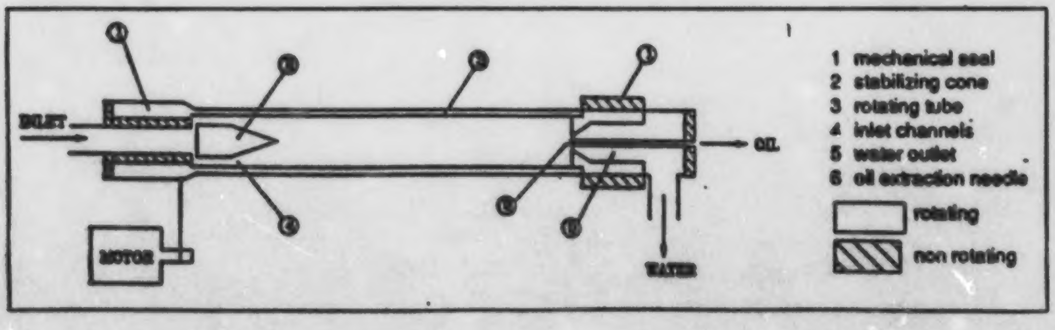


Figure 7. Schematic of the rotary hydrocyclone.

The CSPI static hydrocyclone has been tested in the field on produced water at one in-situ heavy oil recovery site in Western Canada,[19] but results of these tests have not been released. The Dynaclean rotary hydrocyclone has not been tested in the field for the treatment of produced water from in-situ heavy oil recovery operations.

SILICA REMOVAL

As shown in Table 1, the maximum concentration of silica in the feed water to once-through oil-field steam generator has traditionally been recommended as 50 mg/L by the steam generator manufacturers.[1] In actual practice, however, several operators in California have been using feed water with silica concentrations as high as 120 to 268 mg/L.[20] Therefore, at present, there is no consensus among steam generator vendors and users on the question of maximum silica concentrations in the feed water. Some claim that concentrations as high as 150 mg/L are acceptable, while others consider 150 mg/L to be excessive. When treatment of the produced water for silica removal is required, lime softening processes are conventionally employed. These generate significant mounts of sludge and the disposal of this sludge is becoming increasingly costly and difficult due to environmental concerns.

Produced waters from in-situ heavy oil recovery operations at some locations in Western Canada contain silica levels considerably higher than 50 mg/L. Therefore, research work over the last several years has attempted to address the question of silica concentrations in produced water from two perspectives; (1) operation of oil-field steam generators at high (>>50 mg/L) silica concentrations, and (2 development of silica removal processes which will minimize sludge generation.

High Silica Feed to Steam Generators

To evaluate the technical feasibility of using high silica produced water (>>50mg/L) as feed to the oil-field steam generators, a pilot plant facility was constructed and operated by Shell Canada in 1987-88. The study was jointly funded by Shell and AOSTRA.[21] The main purpose of the study was to determine if produced water at Shell's in-situ heavy oil extraction facilities near Peace River, Alberta, could be used in oil-field steam generators without dilution or silica removal.

A simplified schematic of the pilot plant used in Shell's study is shown in Figure 8. The pilot plant included a 1610 kW (5.5 MMBtu/h) high pressure steam generator specifically designed and built for the study. In addition, it had oil removal and softening equipment, the necessary tankage and utilities, as

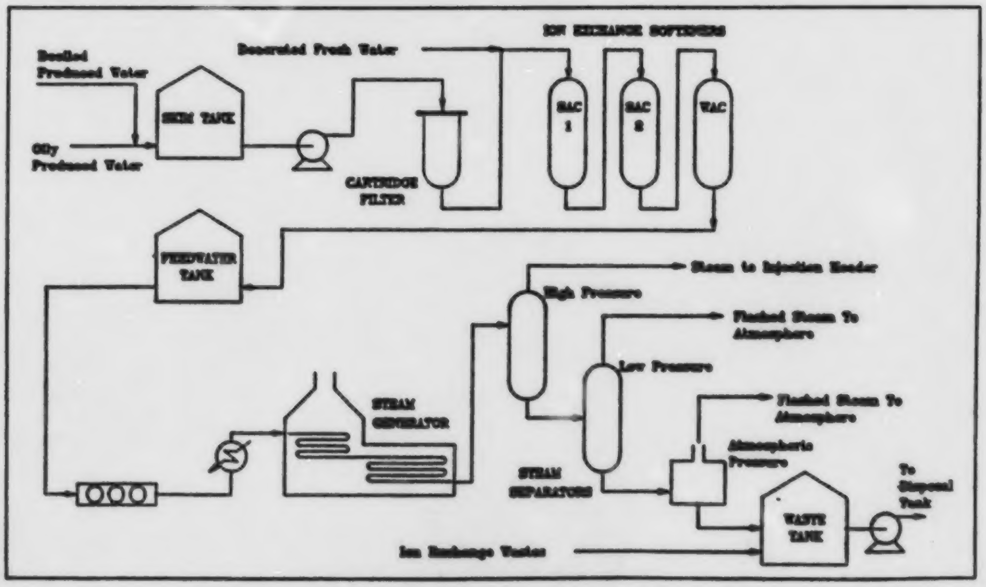

Deoiled
Produced Water
Deaerated Fresh Water
ION EXCHANGE SOFTENERS
SKIM TANK
Oily
Produced Water
CARTRIDGE
FILTER
SAC
1
SAC
2
WAC
FEEDWATER
TANK
Steam to Injection Header
High Pressure
Flashed Steam To
Atmosphere
Low Pressure
STEAM
GENERATOR
Flashed Steam To
Atmosphere
Atmospheric
Pressure
STEAM
SEPARATORS
To
Disposal
Tank
WASTE
TANK
Ion Exchange Wastes

Figure 8. Schematic of pilot plant used in Shell's study.

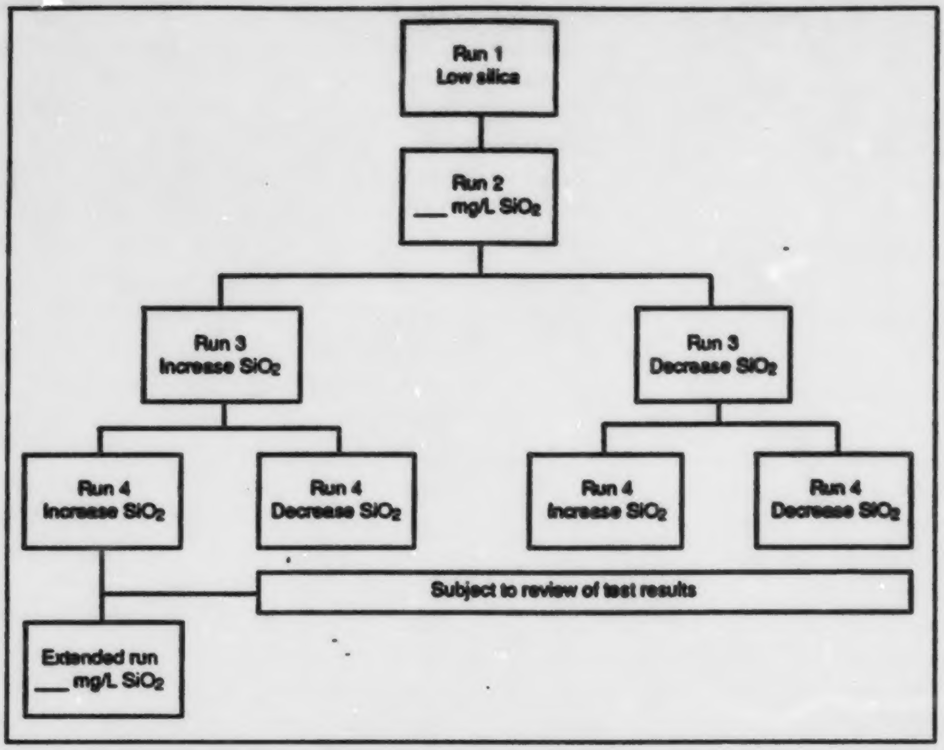


Figure 9. Experimental scheme used during Shell's pilot tests.

well as a computer-based process control and data acquisition system.

To evaluate the severity of scale formation due to silica, the pilot plant was deliberately operated at feed water silica levels substantially above 50 mg/L. The experimental scheme used during the pilot tests is depicted in Figure 9.

Details of the study (and the results) are expected to be available in the near future in a report from AOSTRA.[22] It appears that the results did not support the contention that the steam generators at Shell's Peace River, Alberta, facilities could be safely operated at silica concentrations approaching 150 mg/L in the feed water.[23] It was, therefore, concluded that it would be desirable to evaluate alternative silica removal processes which offer the potential for minimizing sludge generation. If a cost-effective sludge-free process for removing silica is not demonstrated in the future, the industry will have no choice but to continue to rely on dilution and/or lime softening to prepare produced water for recycle to the steam generators.

Low-Sludge Silica Removal Processes

There are two main technologies which look promising for silica removal from produced water with minimum sludge production. These are (1) activated alumina adsorption, and (2) thermo-softening.

Activated alumina adsorption. Activated lumina is the common name for gamma aluminum oxide. It is commercially available as an analytical reagent in small quantities, and as an adsorbent in large quantities. Its ability to remove silica from aqueous solutions through the adsorption processes-s has been documented in the published literature, and a U.S. patent[24] has been issued on the use of activated alumina for the selective removal of silica from industrial wastewaters.

In Canada, some preliminary experimental work has been conducted to evaluate the effectiveness of the activated alumina adsorption process for removing silica from produced waters. This work was conducted in two independent studies — one conducted by Shell Canada[25] and the other by Environment Canada's Wastewater Technology Centre (WTC).[26] The study by Shell Canada involved the use of bench scale continuous-flow adsorption columns packed with activated alumina. The columns were fed with oil-free produced water from Shell's Peace River, Alberta, facilities. The study by the WTC involved batch adsorption and desorption tests to evaluate the potential fouling of activated alumina during its use for silica removal from produced waters. The results of the study by Shell have not been published, but those of the WTC study are available.[26] The main conclusion from these preliminary studies was that the activated alumina, while effective in removing silica from produced water, will not be cost effective unless a technique can be developed to substantially minimize the irreversible adsorption of silica on activated alumina.

These studies did not investigate the relationship of various silica species typically present in produced waters to the observed irreversible adsorption of silica on activated alumina. One interesting insight gained from the WTC study was the fact that the presence of model organic compounds in the water did not interfere with the adsorption of silica on activated alumina. These model compounds were chosen because they occur in produced waters in relatively high concentrations. Therefore, it can be expected that organic fouling would not reduce the ability of activated alumina to remove silica from produced waters. Discussions are currently ongoing between various interested parties in Canada to initiate additional work on silica speciation and activated alumina adsorption.

Thermo-softening. In 1983, Exxon Production and Research Co. of USA filed a patent[27] application on the "thermal softening process" based on the work conducted by the scientists t its Canadian subsidiary, Esso Resources Canada Ltd. The patent covers the removal of hardness from hard waters by the injection of live steam to raise the temperature of the water to between 190 and 210°C at a pH in the range of 9 to 12. More recently, under a program proposed by Monenco Canada Ltd. of Calgary, Alberta, a study[28] has been funded jointly by Monenco, AOSTRA and the Department of Energy, Mines and Resources Canada, to evaluate the effectiveness of the lime "thermo-softening process" for removing hardness and silica from the produced waters.

In both the "thermal softening process" and the "lime thermo-softening process, hardness is removed from the produced water by precipitating salts of calcium and magnesium at high temperature and pH conditions and filtering out these precipitates. The high pH is obtained by the addition of lime and the temperature is raised by the injection of live steam. While the chemistry of the thermo-softening process is well understood, engineering problems related to the effective removal of oil from produced waters before the thermo-softening reactor, and the separation of precipitated salts from the reactor effluent need additional developmental work.

Esso Resources has continued to research and test the thermal softening process in Canada at its in-situ heavy oil recovery operation in Cold Lake, Alberta, to establish the technical and economic feasibility of the process for treating produced water at that location.[29] Monenco is currently negotiating with other potential joint partners to jointly fund the next phase of their developmental work.[30] The data from the ongoing work under Esso's and Monenco's studies are currently not available in the published literature.

TDS REMOVAL

As indicated earlier, there are some areas in Western Canada where the TDS concentration in the produced water is too high to allow its recycle. Therefore, work has continued in Canada to evaluate alternative TDS removal processes. This work includes (1) a literature review and preliminary cost comparison of potentially suitable TDS removal processes, and (2) evaluation at bench and pilot scale of some of these processes.

In 1985, the WTC conducted a review[31] of the literature on TDS removal processes. The processes which were found to be most suitable for produced water treatment were vapour compression evaporation (VCE), electrodialysis (ED) and freeze desalination. Recent development- in membrane technology indicate that membrane distillation may also be a promising technology.

Vapour Compression Evaporation

Vapour compression evaporation is a well-established TDS removal process that is used for seawater and brackish water desalination, as well as other wastewater treatment applications. Because of its advanced state of development compared to the other TDS removal processes, VCE was selected as the first process for experimental evaluation for the produced water application.

In VCE, vapours are produced by initially heating the incoming saline water. The vapours produced are compressed in a mechanical compressor and are then routed through the inside of the evaporator heat exchanger tubes as schematically shown in Figure 10. The vapours cool and condense, producing distillate or TDS-free product water. Upon condensation, the vapours release their latent heat of evaporation via heat transfer through the evaporator tubes to heat and vaporize the incoming saline water.

The use of VCE for TDS removal from produced water has been evaluated at bench[32,33] and pilot scale[34] by the WTC. The pilot study was a joint AOSTRA, oil industry and WTC project which was conducted at Murphy Oil's Lindbergh, Alberta, facilities. The objectives of the pilot VCE tests were; (1) to evaluate the technical feasibility of the process, (2) to identify operating problems resulting from the produced water service, and (3) to develop cost estimates for a full-scale process for treating produced water. A commercial horizontal-tube spray-film VCE unit capable of treating approximately 55 m^3/d of produced water was used in the pilot tests.

The tests involved determining the most suitable water recovery rate and cleaning frequency for a full scale vapour compression evaporator operation.

At the start of the tests considerable amounts of bulky solids and scale were produced. This led to very short- run times and plugging of the VCE sump and lines. Pre-treatment of the produced water was successful in minimizing the scale formation to the extent that extended operation (>500 hours) was possible between cleaning of the tubes with a descaling solution.

The results of the study indicated that VCE was a technically feasible process for TDS removal from produced water, and that the quality of the distillate produced met the requirements of the steam generator feedwater. Assuming cleaning would be required every 500 hours at a water recovery of 67, cost estimates were developed for a full-scale, forced-circulation, vertical-tube VCE system. The capital and operating costs for a full scale system treating 3000 m^3/d of produced water were in close agreement with the preliminary cost estimates based on bench scale tests. Details of the study are available in a report[34] being distributed by AOSTRA.

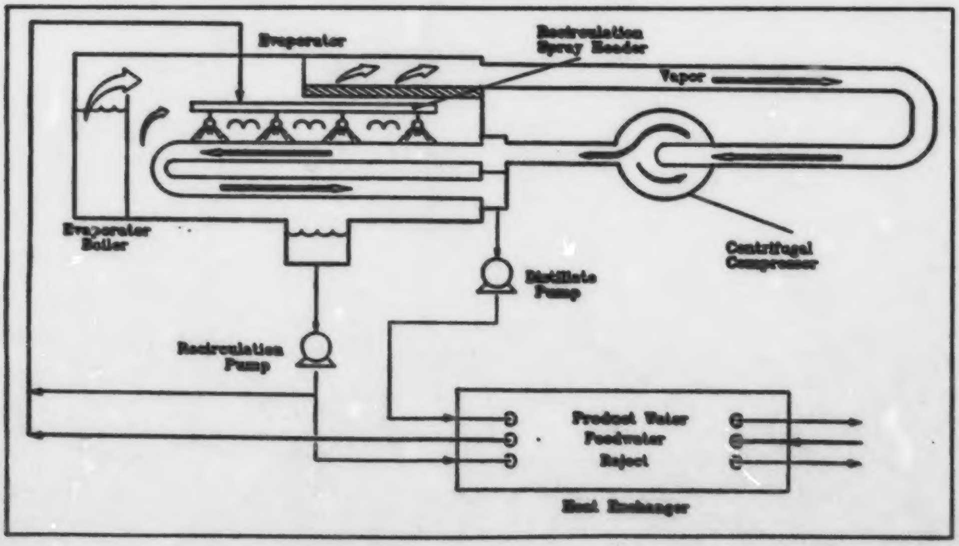


Figure 10. Schematic of vapour compression evaporation process.

Electrodialysis

Electrodialysis (ED) involves the use of charged polymeric membranes and an electrical current to cause separation of the ionic species from the produced water. A simplified schematic of the ED process is shown in Figure 11. A review of the available information on ED and produced water by the WTC[31,35] indicated that the ED process may be competitive with VCE for this application if the problems due to membrane fouling could be minimized and if the ED could be operated at high temperature (80°C).

Under a recent study[13] jointly funded by the WTC, AOSTRA and the oil industry, ED was evaluated at bench-scale at an in-situ heavy oil recovery site in Western Canada. The objectives of the work were; (1) to compare UF and MF as pretreatment to the ED process, (2) to determine whether membrane fouling would cause serious operating problems, and (3) to determine if there would be other operational problems specific to the produced water treatment application.

The results indicated that there was no difference in the behaviour of the ED process whether the feed was pretreated with MF or UF. Slight fouling of the ED membranes occurred during the tests, although the inherent membrane properties (ion exchange capacity and perm selectivity?) were not substantially affected. An ED plant capable of operating at produced water temperature of 80°C is currently being built by the WTC for field tests which are expected to start early in 1991.

Freeze Desalination

In freeze desalination, the saline water is cooled to a temperature at which a portion of the water freezes and forms ice crystals of pure water. These crystals are then separated from the remaining concentrated solution and melted to produce the product water. The cooling of the feedwater can be accomplished by a variety of different techniques such as vacuum freezing, indirect cooling in a heat exchanger, or direct cooling by a refrigerant mixed in the feed water. A review of the available freeze desalination technologies by the WTC indicated that for the produced water treatment application, the vacuum freezing process was the most attractive alternative. This process involves the application of a vacuum to reduce the boiling point of the feedwater to a level where its boiling point is the same as the freezing point. As the vapours form, heat is removed from the feedwater resulting in the formation of ice crystals. The vapours are withdrawn and condensed to produce a product water. The ice crystals are then separated from the concentrated liquid phase, and are washed and melted to produce additional product.

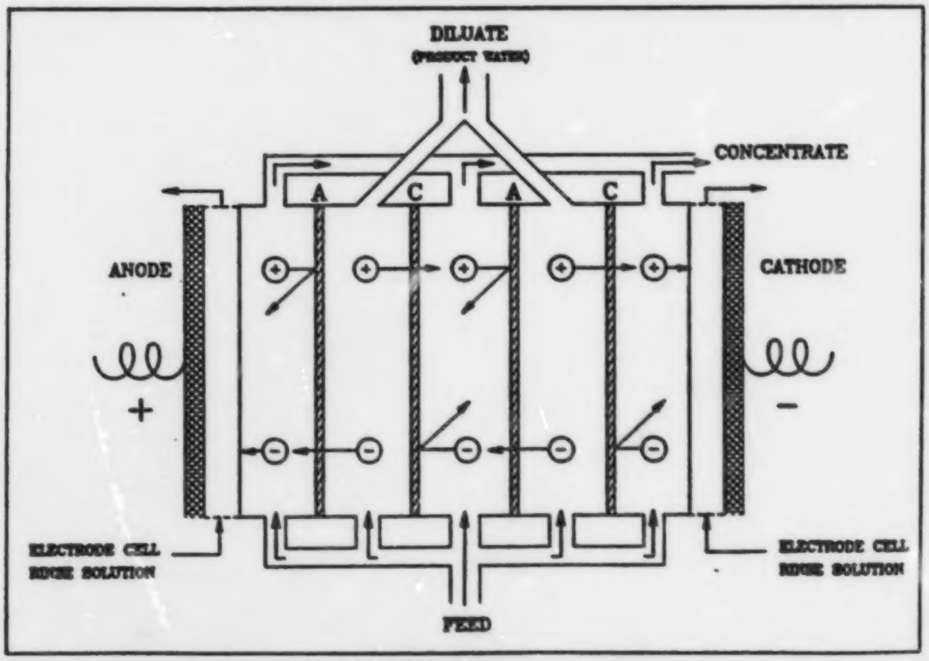


Figure 11. Schematic of electrodialysis process.

As shown schematically in Figure 12, the vacuum freezing process typically has three sections; (1) freezer/crystallizer, (2) ice washer, and (3) melter. Of the vacuum freezing processes developed to date, the "desublimation vacuum freezing process," developed by Calyxes R&D of Albuquerque, New Mexico, U.S.A., has been tested on produced water samples from Western Canada in off-site pilot-scale tests.[36] The objective of this work was to determine if the process was sufficiently developed to justify field tests.

During the pilot plant work, a number of problems were experienced related both to equipment design (air leakage into the vacuum freezing chamber and malfunction of the crystal washing column) and to difficulty in handling the residual oil and foaming agents present in the produced water samples. It was concluded that further development is necessary before this technology would be suitable for produced water treatment. Field tests were, therefore, postponed until such time as the process is sufficiently developed to justify field testing.

Membrane Distillation

Membrane distillation (MD) is a relatively new membrane process which involves passing high TDS water on one side of a highly hydrophobic, porous membrane. Pure water vapours pass through the membrane wall where they are condensed to produce product water. Figure 13 shows a schematic of the process.

One key advantage of membrane distillation for the produced water application is that the thermal energy of the produced water, which is normally at a temperature of 80°C, can be utilized as the driving force for the process. Other advantages include; (1) the high degree of concentration (supersaturation of sodium chloride) and high water recoveries that can be attained, and (2) the relatively inexpensive materials of construction (high temperature plastics) that can be used for the full-scale design. The technology is not yet at a commercial stage but test systems are available from a few sources.[37,38]

Recently the WTC has initiated preliminary tests on the application of MD to produced water. Results from these tests should be available over the next several months. If these results are promising, further work on the application of MD to produced water will likely continue through bench and pilot scale field tests in order to evaluate its technical and economic feasibility.

DIRECTION OF RESEARCH IN CANADA ON PRODUCED WATER TREATMENT

The R&D work conducted on produced water treatment in Canada over the last several years has provided better appreciation of the difficulties associated with the treatment of produced waters from the in-situ heavy oil recovery operations. It has also identified certain areas where opportunity exists for significant improvements in our ability to recycle

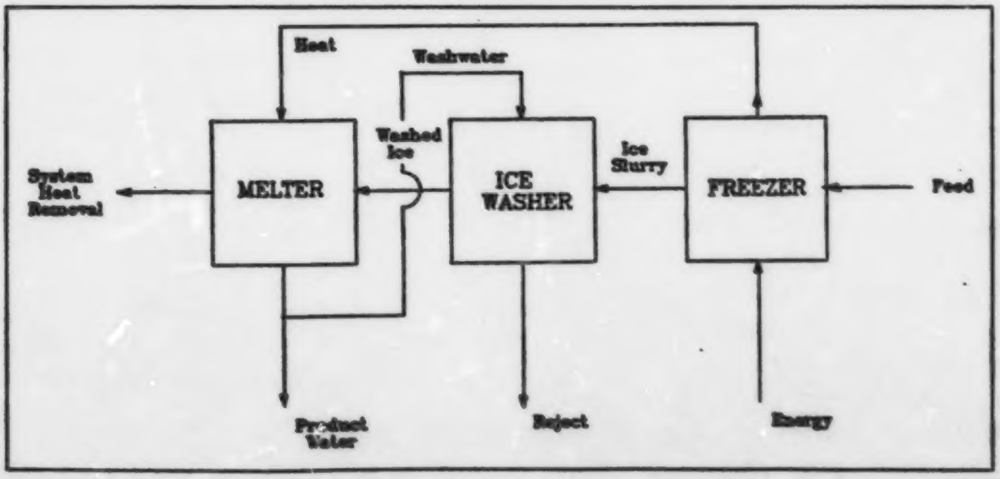


Figure 12. Schematic of vacuum freezing process.

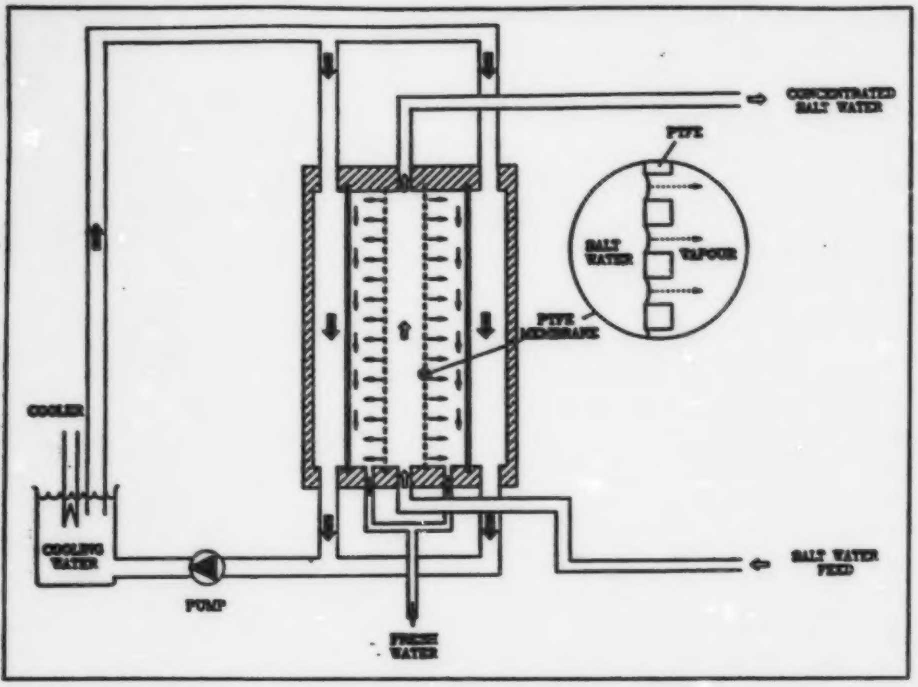


Figure 13. Schematic of membrane distillation process.

the produced water to the oil-field steam generators. Some of the R&D activities are currently continuing, and several more are expected to be initiated in the near future.

In the area of oil and suspended solids removal, the erratic performance of the conventional produced water treatment systems is still a problem despite modifications in skim tank design and operation of the granular media filters. Consequently, the use of alternative processes such as membrane technology and hydrocyclones is being assessed. Work conducted to date on the use of the membrane technology for oil and suspended solids removal has identified several problems. The problems relate in part to the varying nature of the produced water and in part to the performance of the membrane systems that have been tested to date. Generally, however, it is felt that the potential of membrane technology for oil and suspended solids removal is very good. It is expected that a study will be initiated soon to systematically evaluate up to 20 commercially available and experimental membranes for oil and suspended solids removal from produced water from in-situ heavy oil recovery operations in Western Canada.

In the area of silica removal, the lack of a good understanding of the different silica species that can exist in produced water is currently hampering progress in the proper selection of silica removal processes, as well as in the determination of the maximum tolerable concentration of silica for the oil-field steam generators. It is expected that work in this area would start in the near future to identify various silica species in produced water of Western Canada, and to resolve the problems associated with the removal of silica from these waters.

TDS removal from produced water will be required in some parts of the heavy oil producing regions of Western Canada. Until 1985, no technologies suitable for TDS removal from produced water had been evaluated. Since that time, vapour compression evaporation has been evaluated at pilot scale, and electrodialysis will be evaluated at pilot scale in 1991. Further process development work in this area would likely focus on membrane distillation and freeze desalination.

ACKNOWLEDGEMENTS

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COAL FIRED STEAM GENERATION FOR HEAVY OIL RECOVERY

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Shell Canada Limited

INTRODUCTION

The Province of Alberta currently produces some 21,000 cubic metres per calendar day of heavy oil and bitumen by in-situ recovery methods involving the injection of high pressure steam (11000 Kpa–17,200 Kpa) into the reservoir for mobilising and recovering the oil. The amount of steam required depends on the nature of the reservoir and the particular recovery technology used. Typical oil to steam ratios vary between 0.25 and 0.35. An oil to steam ratio of 0.3 would indicate that some 70,000 cubic metres of steam per calendar day are required for current bitumen production.

This steam requirement is produced in standardised natural gas fired oil field steam generators of 190 Giga joules per hour individual capacity. Design of the generators has been standardised to handle the unique conditions required for steam generation in in-situ heavy oil applications. In these applications steam is used as the mechanism for transferring heat to the reservoir. It is required at pressure to fracture the reservoir for improving reservoir permeability and in some cases to drive the mobilised oil to the producing well. Steam of 80% quality is acceptable for this purpose, reducing the requirement for feed water treatment and making in feasible to reuse water or use coproduced water which in large quantities would otherwise require an environmentally acceptable means of disposal. The size of the generators has been limited to a maximum suitable for transportation by road. Clusters of generators are normally required to provide the full steam requirements at the heavy oil site. There is therefore a very large sunk investment for industry in this generator design which must be considered when considering a change of fuel.

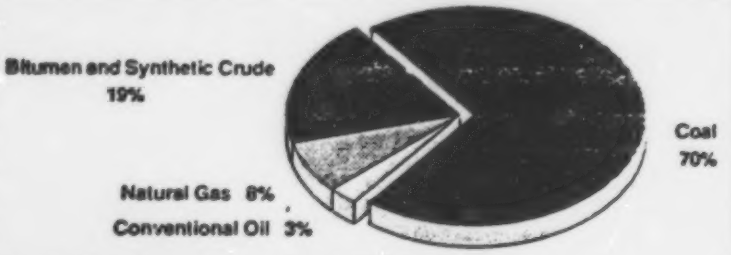
Although various alternate fuels such as coal, bitumen, petroleum coke, wood and electricity are available for steam generation, natural gas has been selected as the fuel of choice for its relatively low cost per unit of energy, the ease with which it can be transported to the operating sites, and the simplicity of gas utilisation technology. Also, gas has the additional benefits of being the "cleanest" burning fossil fuel while at the same time providing the lowest levels of gaseous emissions per unit of available energy.

Within Alberta, natural gas is in plentiful supply and therefore competitively priced compared to other fuels. Consequently a substantial general increase in the demand for natural gas has occurred. Large increases in demand could lead to significant price increases. If large price increases do occur, the profitability of insitu oil sand operations, with a large portion of their operating costs fuel related, would be adversely effected.

It is for this reason that in 1985 heavy oil producers along with government commissioned a study to look at the opportunities for replacing natural gas used for steam generation with an alternate fuel. The study concluded coal was best placed to become an economic alternative to natural gas and solid fuel burning technology was sufficiently advanced worldwide for its consideration for heavy oil steam generation applications. However, further work was considered necessary to demonstrate the technical viability of pulverised coal firing of the typical oil field steam generator currently used by heavy oil producers.

COAL AS AN ALTERNATE FUEL FOR STEAM GENERATION

Coal is Alberta's most abundant fossil fuel resource accounting for 70 percent of all fossil fuel reserves. It is also the most underutilised resource in terms of its overall reserve base. At current consumption rates the life of Alberta's coal reserve far exceeds the life of all other fuels combined. Figure 1 shows a breakdown of Alberta's energy reserves.



Source: Alberta Energy Resources Conservation Board – 1989

Figure 1. Alberta's energy resources.

Most of Alberta's coal reserve, 84 percent, is of sub-bituminous rank and low in sulphur content. Figure 2 provides a typical analysis of sub-bituminous coal presently mined in Alberta for use in electrical power generation. Approximately one third of the sub-bituminous coal reserve, is amenable to low cost surface mining techniques: however, its relatively low energy content limits the distance over which it can be transported and remain economically competitive with other fuels.

Proximate analysis (as received)	
Moisture	25%
Ash	12%
Volatile matter	27%
Fixed carbon	36%
Sulphur wt%	0.4
High heating value	18.14 MJ/kg

Figure 2. Typical Alberta sub bituminous coal.

Alberta's major oil sand deposits are located in three distinct geographical areas — Peace River, Athabasca and Cold Lake with insitu bitumen production coming from the Peace River and Cold Lake areas. The reserves of sub-bituminous coal are, as shown in Figure 3, within reasonable proximity to these oil sand resources.

For coal to be considered as a viable alternative to natural gas various technical issues need to be addressed including, environmental emissions control; transportation and coal utilization (combustion and handling). A broad range of technical options are available to deal with these issues. The evaluation of these options has been the subject of various industry/ government studies.

In order for the technical options to be evaluated economically against the use of natural gas, views have to be taken as to future price projections for both coal and natural gas. It is expected that the price of sub-bituminous coal in Alberta will be relatively fixed in real terms due to the large resource base and the limit by its energy content for transportation 10 alternate markets. On the other hand, the future price of natural gas is less certain as X is more transportable and therefore exposed to the international forces of market supply/demand.

The conversion to coal once taken can provide the heavy oil producer with a reasonably assured fuel supply over a long time frame together with a relatively stable energy cost.

ENVIRONMENTAL CONSIDERATIONS

The environmental performance of coal for firing heavy oil steam generators is critical to its acceptance as an alternate to natural gas.

Coal firing results in the emissions of three major gaseous components; the oxides of sulphur (SO_2), Nitrogen (NO_x) and carbon (CO_2). Emphasis to date has been placed on the impacts of SO_2 and NO_x as the precursors to acid rain, and strict environmental standards have been put in place to limit their emission. The potential for global warming resulting from the build up of greenhouse gases in the earths

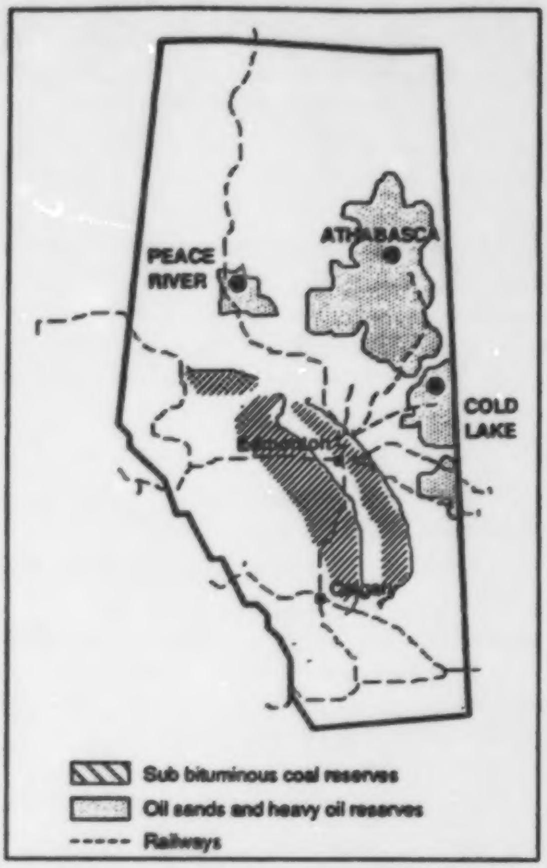

PEACE RIVER
ATHABASCA
COLD LAKE
Edmonton
Calgary
Sub bituminous coal reserves
Oil sands and heavy oil reserves
Railways

Figure 3. Location of Alberta's oil sands and sub bituminous coal resources.

atmosphere is now bringing to the forefront concerns over the levels of CO_2 emitted by the combustion of fossil fuels and in particular coal since it has the highest carbon content per unit of available energy.

The current Canadian federal guidelines and Alberta provincial regulations, for maximum emissions of SO_2 and NO_x from large coal fired plants, are 258 ng/J for both gases. It is expected that coal fired steam generators for heavy oil recovery will also have to meet these limitations.

A review of the technologies available for reduction of SO_2 and NO_x from coal combustion as applied to heavy oil recovery steam generators has been carried out. The technologies, categorised into combustion and post combustion, are shown in Figure 4. The review looked at both the removal capabilities and the cost for the various technologies. Combustion control technologies were found generally to be less costly than post combustion flue gas clean up.

Other environmental considerations which need to be addressed in the design and operation of coal fired steam generators include the control of particulate emissions (fly ash and coal particles), the disposal of boiler and fly ash, the management of the boiler feed water and subsequent disposal of boiler blowdown water.

NO_x emission control	SO_x emission control
Combustion modification:	Combustion modification:
Low excess air	Advanced slagging combustors
Staged combustion	Sorbent injection
Flue gas recirculation	
Water or steam injection	
Fuel staging (reburning)	
Advanced slagging combusters	
Non-selective catalytic reduction	
Post combustion methods:	Post combustion methods:
Selective catalytic reduction	$NaHCO_3$ duct injection
$NaHCO_3$ duct injection	$Ca(OH)_2$ duct injection
Lime spray drying (with NO_x additive)	Lime spray drying
Lime/limestone wet scrubbing (with No_x additive)	Lime/limestone scrubbing
Dual alkali (with Nox additive	

Figure 4. Emission control technologies.

ASPECTS OF STEAM GENERATION FOR HEAVY OIL RECOVERY

In Alberta, steam generation for heavy oil recovery is accomplished by the utilisation of 190 GJ/hr gas fired once-through steam generators. Multiples of these generators are normally clustered in groups and centrally located to provide the total steam requirements for a particular area of the reservoir. The size of the individual generator is determined by the desire of the heavy oil producers to fabricate the generator in a manufacturing centre and transport the generator, normally in two to three components, by road for final erection at the heavy oil production site. The ultimate size of the generator is therefore determined by the maximum load allowable by road transportation.

The gas fired steam generator consists of a once-through single pass water tube boiler with a feed water heat exchanger, convection section and radiant section. The feed water is typically preheated to prevent external tube corrosion in the convection section where heat is scavenged from the flue gas. From the convection section the water passes to the radiant section where the water tubes are exposed to the flame and the water is vapourised. Approximately 80% of the feedwater is converted to steam leaving 20% of the water to carry off remaining dissolved solids and to prevent solid deposits forming on the tube walls.

The quality of the feed water dictates the design and operation of the steam generator. Two sources of water are typically available for use by the heavy oil producer: surface water from lakes and rivers requiring minimal treatment other than filtration and softening prior to use; and reservoir (produced) water containing a high level of dissolved solids requiring significant pretreatment to soften the water and reduce the level of dissolved solids, particularly silica, which otherwise would result in solids deposition and erosion of tube surfaces.

The concern with accessibility to large volumes of surface water for steam generation and the need to subsequently dispose of produced water, generally by injection into a suitable subsurface formation, require that in large scale operations produced water is recycled for use in steam generation. This requires that in addition to pretreatment of the produced water, currently with hot lime softeners, the steam generators are operated at low heat flux and 80% steam quality to prevent rapid vaporisation of the feed water and consequent deposition of solids on the tube walls.

In the application of coal firing to steam generation for heavy oil recovery, the need for once through generation of 80% quality steam at low heat flux are critical design parameters which differ from the more typical application of pulverised coal firing in boilers associated with electrical power generation.

CONVENTIONAL PULVERISED COAL FIRED STEAM GENERATION

In 1988, a joint Canadian Industry/Government committee commissioned a study to design and cost a pulverised coal fired steam generator suitable for use in insitu heavy oil applications. Following the study it was intended to use the design as the basis for the construction of a prototype steam generator to demonstrate the technology. The prototype generator was to be designed to handle a variety of Alberta coals and would need to meet government guidelines for for limiting the gaseous emissions of SO_2 and NO_x.

STEAM GENERATOR CONFIGURATION

Various steam generator and burner configurations were evaluated in 1he study. Multiple burner, tangential corner burner and single burner arrangements were considered. The study indicated that multiple burners would be more costly than a single burner and in most cases, multiple burners also resulted in higher peak heat fluxes. Therefore, only steam generator configurations having a single burner were given further consideration and these are shown schematically in Figure 5.

Configurations A and B incorporate a single burner firing vertically downward into a square section furnace with tubes laid out in a horizontal or inclined configuration to allow self draining and averaging of heat flux. The gas flow leaving the furnace flows horizontally through a cavity and

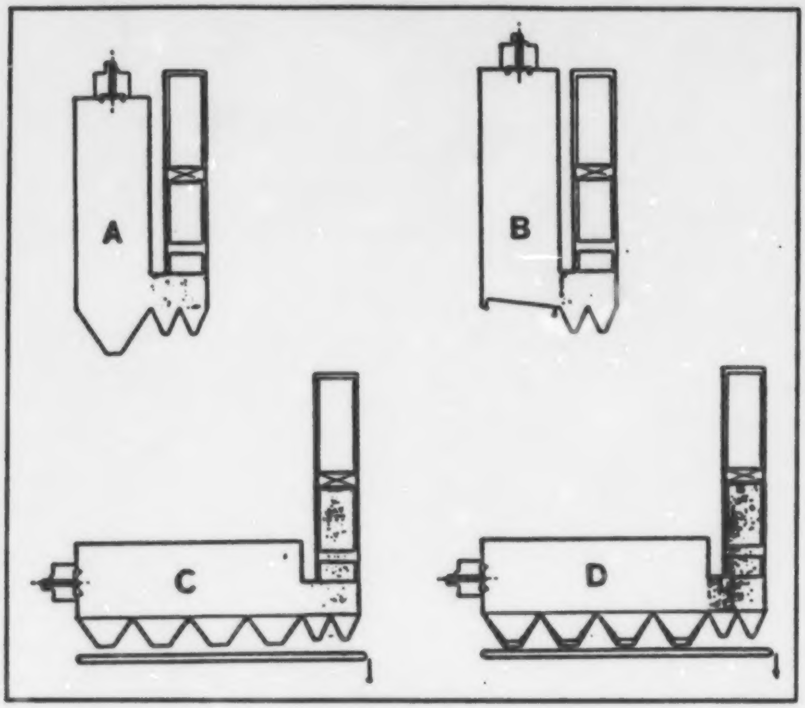


Figure 5. Steam generator configuration schematics.

vertically upward through an evaporator and economizer section. The steam and water mixture flows upward through the water cooled furnace. The two configurations differ only in the manner of ash collection and removal. Configuration A utilises a conventional water cooled hopper, whereas the inclined furnace floor of B is covered by a stationary grate section with air nozzles assisting in both cooling and removing the ash into an adjacent ash collection hopper.

Configurations C and D consist of a horizontal furnace fired with a single burner in the front wall. The waterwalls are comprised of intermeshed tubing forming the floor of the unit and integrated into a welded wall covering the sides, roof as well as front and rear walls. Tubes are laid out essentially horizontal, moving sequentially around the furnace. The welded wall construction provides a gas-tight wall surface and prevents ash migration into the insulation or surrounding environment. The cool, smooth surface of the waterwall also assists in minimizing accumulation of ash deposits. The gas flow leaves the furnace horizontally and flows upward through an evaporator and economizer section similar to configurations A and B.

Again, the only difference between the two configurations, C and D, is in the means of ash handling. In configuration C the ash simply falls between the two rows of screen tubes forming the furnace floor and is collected in a number of hoppers beneath the furnace and convection sections. In configuration D the ash falling through the screen tube floor falls onto the smooth floor surface which incorporates intermittent compressed air grate cleaning nozzles and a quantity of cooling and fluidizing air to keep the ash in suspension above the floor and convey it to a drag conveyor located beside the furnace.

All steam generator configurations incorporate an evaporator section which takes the steam water mixture leaving the furnace at approximately 50% quality and converts it to its final condition of 80% quality steam. This arrangement reduces the heat flux during final evaporation from the furnace radiant zone thereby minimizing the risk of deposition or burnout should an uneven flow condition occur. The likelihood of deposition or corrosion is further reduced as a result of moving the circuit region, where the highest quality steam is produced, from a radiant zone to a non radiant zone where the heat flux is approximately one third that of the radiant zone.

Dual Economizers are utilised to reduce the flue gases to their desired exit gas temperature by heat transfer with the incoming boiler feed water.

All configurations incorporate the ability to add calcium sorbent to control SO_2 emissions.

ASH REMOVAL

The design of the generator ash removal system is dependent on the quantity of ash contained in the coal and the characteristics of the ash and slag to be removed from the furnace. Since all the steam generator configurations considered have radiant sections designed to have low heat release rates, peak flame temperatures are expected to be well below the initial deformation temperature of the coal. Therefore, very Little ash agglomeration or build up on the furnace walls is expected. Ash remaining in the radiant section should remain light and fluffy over lengthy periods. If necessary, soot blowers can be incorporated in the walls of the furnace to re-entrain the ash into the gas stream.

Of the four steam generator configurations considered, the vertical units provide the best design from an ash collection and removal standpoint. The area forming the furnace bottom is one third the size of the horizontal units and the ash collection zone in these units is expected to have a lower range of operating temperatures.

The conventional water cooled ash hopper utilised in configuration A is most suitable when significant quantities and size ranges of agglomerated ash particles are to be removed. However n requires the greatest overall building height and has the highest cost. The system schematically shown in B illustrates a stationary alloy grate with cleaning nozzles which is both water cooled and air cooled and is utilized to blow the ash into the adjacent hopper. In contrast, this concept is expected to be the lowest in cost and will require the lowest maintenance.

SELECTED STEAM GENERATOR CONFIGURATION

The configuration outlined as option B in Figure 5 and further detailed in Figure 6 was selected as the basis for design for having the following advantages:

- more compact arrangement and smaller footprint, thereby requiring less building space
- most effective use of the furnace waterwall surface
- furnace floor tubes are furthest from the burner (least chance of slag formation on the floor)
- except for alternative A, furnace ash will have the lowest temperature
- the stationary grate removal surface is integral within the furnace thereby requiring no seals between pressure parts and the ash hopper
- the furnace bottom configuration is robust and does not allow radiation through to the ash hopper
- has reasonable backup capability for manual ash removal in case of maloperation or the burning of a lower quality higher ash coal.

CONSIDERATIONS FOR SO_2 EMISSIONS CONTROL

To meet the current Canadian federal government guidelines for SO_2 emissions from coal fired utility boilers, utilising low sulphur western Canadian coal, it is necessary to remove approximately 40% of the SO_2 from the gas stream. A review of various methods for accomplishing this reduction was carried

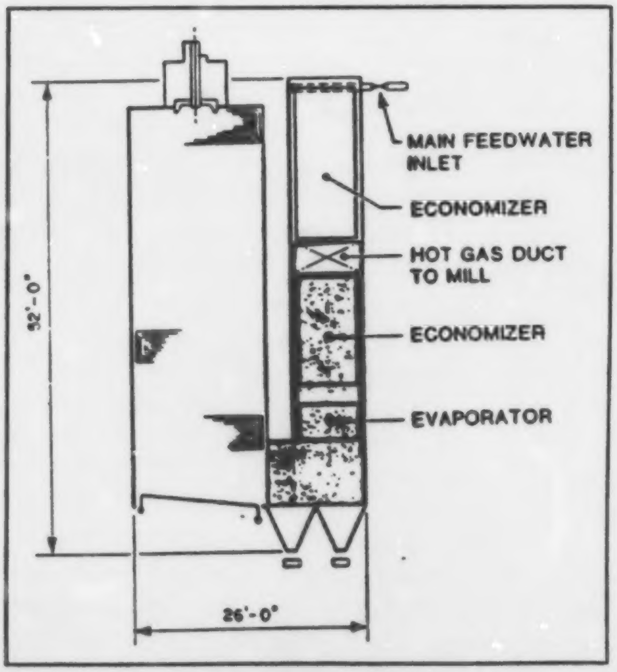


Figure 6. Downfired steam generator.

out in an associated study mentioned previously. Of the methods available, including flue gas desulphurization, sorbent injection into the furnace by adding sorbent to the coal prior to firing was considered as the economic choice. In the event it is required to reduce SO_2 concentrations in the flue gas to lower levels, or a higher sulphur content coal is used, desulphurization of the flue gas by one of the available methods may be required. This would add significantly to the cost of the steam generation facilities.

Furnace sorbent injection technology is based on injecting into the furnace the calcium compound which is sequentially calcined and then partially combined with the SO_2 present in the flue gas. Both these reactions are temperature dependent. Sorbent injected into the furnace which partially reacts with the SO_2 must then be collected from the furnace convection pass and dust collection system and increases the total ash disposal requirement.

Different calcium compounds can be used for furnace sorbent injection and these normally include limestone and calcium hydroxide as the most economically attractive. The choice of calcium compound depends on the particle size, pore volume, reactivity, presence of impurities and cost. An evaluation of water treatment lime sludge, a waste material from the hot lime softeners used for produced water treatment, indicates that it would be an excellent sorbent.

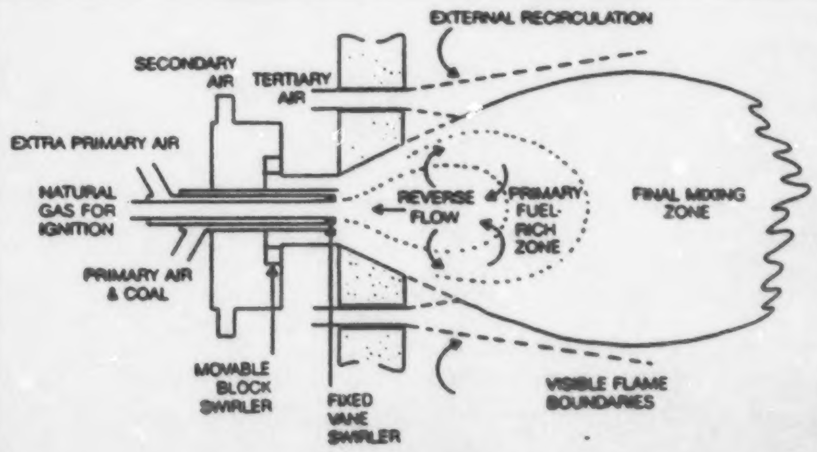
By conservatively sizing the steam generator furnace, compared to other industrial and utility type coal fired steam generators, an optimum residence time can be provided in the furnace to complete fuel burn out and allow the SO_2 in the gas stream to react with the calcium sorbent. Conservative sizing also assists in controlling peak heat flux and minimizing fouling and slagging in the radiant section. The inclusion of calcium sorbent injection results in an increase in the overall furnace length.

CONSIDERATIONS FOR NO_X EMISSION CONTROL

The control of NO_x (NO and NO_2) emissions is accomplished by minimizing peak flame temperatures and providing for fuel rich conditions at the burner to achieve off-stoichiometric conditions within the furnace.

The single burner considered in the design is a turbulent burner incorporating both natural gas and coal firing with approximately 90% of the combustion air passing through the burner throat, the remaining 10% combustion air is introduced as staged air in a similar manner to that shown in Figure 7.

In addition to combustion air staging at the burner, NOx emissions are reduced by diluting combustion air with flue gas. Flue gas is removed at an intermediate section of the economizer and mixed with ambient air to supply heat for drying the coal in the pulverizer. After drying, the air-gas mixture is



(Source: Coal for Enhanced Oil Recovery, Emission Controls Study, Esso Resources Canada Limited, 1988)

Figure 7. Schematic of a typical multi-staged burner.

used to convey the coal to the burner. This recirculation of flue gas via the pulverizer to the the burner dilutes the combustion air and assists in minimizing peak flame temperatures.

By the methods outlined, it is expected that NO_x emissions can be controlled to levels at one half the current Canadian federal government guidelines.

CONTROL OF PARTICULATE EMISSIONS

Particulate emissions in the flue gas can be controlled prior to exhaust to the atmosphere utilising either electrostatic precipitators or a baghouse filtering system. Flash resistivity is dependent on the type of coal and the sorbent used to reduce the SO_2 concentration. The addition of sorbent will also add to the dust loading in the flue gas. For a commercial installation where the coal and sorbent are known before hand, either method of dust capture is technically acceptable and the choice would result from an operational and economic evaluation. In a prototype facility where a number of different coals and sorbents may be tested, a baghouse filtering system provides the greatest flexibility.

The coal fired steam generation system outlined above, and shown schematically in Figure 8, represents a viable design concept which utilises conventional technology modified to suite the particular steam generating requirements for heavy oil production in Alberta, while at the same time meeting the current Canadian guidelines for the emissions of SO_2 and NO_x. The design also provides the basis from which economic evaluations of coal fired versus natural gas fired steam generation may be carried out.

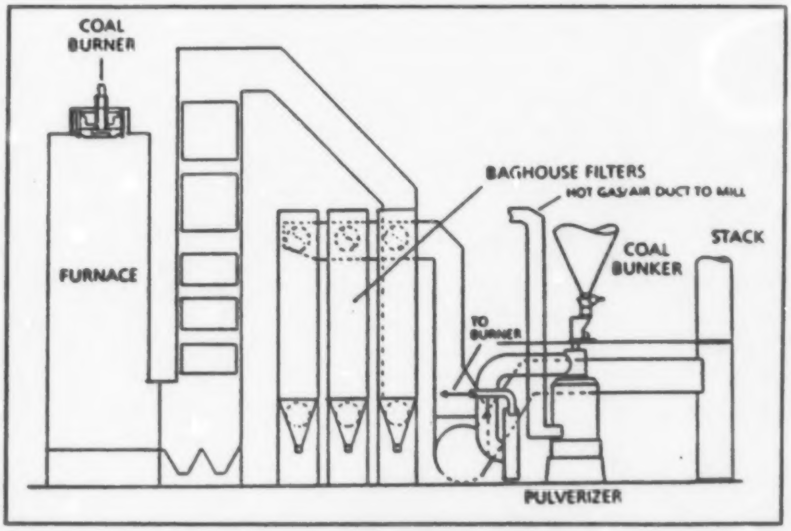
FURTHER COAL COMBUSTION DEVELOPMENTS - THE LNS BURNER

Background

Concurrent with the development of a design for a coal fired steam generator based on conventional pulverised fuel technology, Transalta Resources Corporation, an Alberta based Canadian company is developing a multi-stage slagging type coal fired combuster (the LNS Burner) suitable for application with oil field seam generators.

The technology for the LNS (Low NO_x/SO_x) Burner was developed with the combustion skills acquired in building rocket engines for the U.S. space program. In the late 1970's theories conceived at Rockwell International, a U.S. company based in California, indicated that both nitrous oxides and sulphur dioxide created from the combustion of fossil fuels could be reduced to near zero by what appeared to be a rather simple modification of the coal combustion process. From that beginning, a burner has been developed that will reduce the sulphur and nitrous oxide of the coal before n enters the steam generator furnace.

The burner operates at very high temperatures such that the coal is partially gasified producing a hot syngas and coal mixture which flows into the steam generator furnace where the combustion process continues. At the high operating temperatures of the burner, the ash contained within the coal becomes



(Source: Combustion Engineering Canada Inc.)

Figure 8. Pulverised coal fired steam generator

molten and flows out of the burner to be captured in a slag bath.

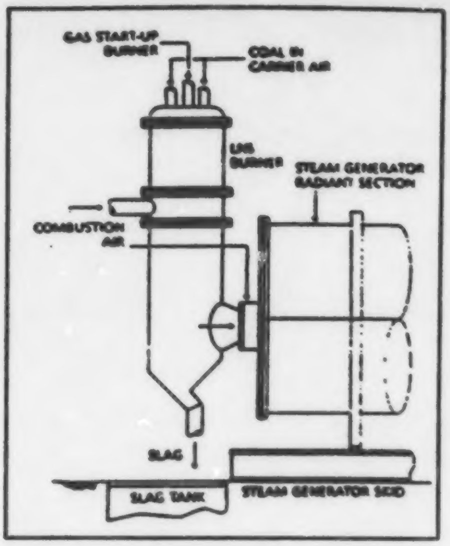
The control of SO_2 is accomplished in the burner through the use of calcium, either inherent in the coal or added limestone, which captures the sulphur and forms a solid compound. With NO_x, the fuel bound nitrogen is first converted to molecular nitrogen within the burner and new thermal NO_x is prevented from forming by staging air addition and maintaining off-stoichiometric conditions as combustion continues through the furnace. An additional advantage of the slagging process is that fly ash is reduced o very low levels such that the burner can be considered for retrofitting conventional gas tired steam generators albeit with some modifications to the design of the end walls in the radiant section.

The capture of SO_2 is particularly effective with coals having a high calcium to sulphur ratio, typical of low sulphur western Canadian sub bituminous coals. In these cases high levels of sulphur capture can be obtained without the addition of limestone. Pilot-scale testing carried out during the 1980's ,now complete, utilising a prototype 25 million Btu/hr burner has demonstrated that with low sulphur sub bituminous coals, simultaneous 70 per cent SO_2 reduction, 80 to 90 percent NO_x reduction and 80 percent fly ash capture can be achieved while maintaining 95 to 99 percent carbon burnout.

Demonstration Project

Based on the pilot scale results and economic feasibility studies sponsored by Industry and Government, the decision has been made to proceed with the demonstration of a scaled-up commercial size burner. A 53 GJ/hr (50 million Btu/hr) heavy oil steam generator, fitted with a single LNS Burner, shown conceptually in Figure 9, has been constructed at a Cold Lake Heavy Oil site. Construction of the facility was completed early in 1990 and is currently proceeding through the commissioning phases.

The project is designed to demonstrate the long-term operability and durability of the LNS Burner on a heavy oil recovery steam generator in a commercial plant setting, as well as the SO_2 and NO_x emission control capabilities of the burner. Figure 10 shows the emission targets for the demonstration project. These are one half the federal government guidelines for SO_2 emissions and one third the guidelines for NO_x emissions.



(Source: LNS Burner on EOR Steam Generator Feasibility Study, TransAlta Resources Investment Corporation, 1989).

Figure 9. LNS burner heavy oil recovery installation.

	Emission guidelines ng/J	Demonstration project targets ng/J
SO_2	256	128
NO_x	256	86

Figure 10. LNS burner demonstration emission targets.

The demonstration facility is located adjacent to an existing commercial in-situ heavy oil recovery gas fired steam generation plant and steam generated at the demonstration facility will be used in the commercial operation.

Following successful demonstration of the technology at Cold Lake, the next phase of technology development for heavy oil recovery applications will be to evaluate scale up the Burner further to full commercial size capable of 190 GJ/hr (180 million Btu/hr), including a critical review of the necessary steam generator modifications and ancillary process technologies. Final commercial use of the technology will depend on its successful development to the commercial size, the economic benefits of at the time and environmental acceptance for using coal rather than natural gas for steam generation.

ECONOMICS OF COAL AS A FUEL FOR STEAM GENERATION IN HEAVY OIL RECOVERY PROJECTS

In addition to the availability of viable technologies for coal fired steam generation must be the economic incentive for the heavy oil producer to utilise coal as an alternative fuel to natural gas. To evaluate this incentive a joint industry/government study was carried out in 1989 to evaluate the differential capital and operating costs of burning coal rather than natural gas using as a basis the conventional pulverised coal fired steam generator design previously outlined.

The study developed costs of transporting coal to the Peace River and Cold Lake heavy oil sites by rail from three different coal resource areas in Alberta. Two configurations of clustered steam generators at the heavy oil sites were considered, a single "six pack" (six 190 MJ/hr steam generators) design and a three by six pack design for determining different levels of fuel requirement.

Natural gas and coal price forecasts used in the study are based on government projections.

Higher initial capital costs (three to five times that for gas) were indicated for the coal fired plant. Also, higher operating costs, excluding delivered fuel costs, were expected for the coal option. In addition, given the existing rail infrastructure, significant investments in railbed upgrading and access to the heavy oil sites would be required for coal transportation, particularly at the higher levels of fuel requirement. However, sufficient differential in energy cost were predicted to occur over time between coal and natural gas to overcome these additional costs.

Project economics were shown to be most sensitive to natural gas prices, coal transportation costs and coal plant capital costs.The energy price forecasts used in the study show a significant gas price increase over the next few years and actual prices will need to track these projections to justify proceeding with any commercial action.

The study concluded for a project timing in the mid 1990's, that based on the fuel price projections and the design and cost premises used in the study, the use of coal for steam generation in heavy oil in-situ projects in the Peace River and Cold Lake areas of Alberta is economic when compared to natural gas.

CONCLUSION

Viable technologies are being developed which will allow the utilisation of coal rather than natural gas for steam generation in in-situ heavy oil operations and meet or exceed the current Canadian environmental guidelines for acid gas emissions. There is significant additional capital cost for the coal fired option, and this additional cost will need to be offset by expected future increases in the differential cost of energy between natural gas and coal.

ACKNOWLEDGMENTS

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THE PRACTICE OF TRACKING NUMERICAL SIMULATION IN THE THIN-LAYER EXTRA-HEAVY OIL PILOT

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ABSTRACT

For developing thin-layer, extra-heavy oil reservoirs, peoples in the industry often ask the questions regarding the effectiveness of the thermal operations and the economical value of such development. The authors present a field case in this paper to introduce a new approach for such reserves development in the Jinglou Zero district, Henan field. This case is based on the fact that the very good results have been achieved technically and economically in the pilot tests by using steam stimulation in the thin-layer, extra-heavy oil reservoirs. A comprehensive evaluation of the steam stimulation performance by using tracking numerical simulation techniques, the characteristics of injection-response in this kind of reservoir are thus recognized. From this, the best development approach, operation strategy, and the forecasts of the steam flooding performance can be established.

The heavy oil reservoirs in the Henan field are characterized by the shallow depth (less than 500 m), thin formation (thickness less than 10 M), and high oil viscosity (greater than 10 000 mPa·s). Its total oil in place is about 70% of the entire heavy oil reserves discovered in that area. For developing this kind of oil reservoirs, the field pilot tests were carried out to identify the operational problems from thermal oil recovery. Through years of steam-injection in a pilot operation at the Jinglou Zero district, the field data and experience could be used as guides to develop this special oil reserves in a way technical soundly and economical efficiently.

RESERVOIR CHARACTERISTICS OF THE TESTING AREA

The pilot area is located in the Qiandulou nose-like structure of Jinglou field, Henan province. The formation exhibits the monoclinal stratum with a dip-angle of about 11.30. The sand body, developed at the setting of beach land, is a composite rhythm formed by multiple sands and mud barriers. With the feature of flood period deposit, the sources of material were multi-directional; and the change of sand properties in the lateral sides was extensive. The strata, buried at the depth of 331.6 to 384.3 meters, are composed of a set of grey-green to light-grey thin-bedded layers of sandstone with gravel, and fine sandstones. The reservoirs are shallow with 2 to 3 layers in this formation. The gross pay of the productive zones ranges from 2.8 to 9.6 meters with the average thickness of 5.45 m. And the net to gross thickness ratio is 0.3 to 0.87 with the average of 0.61.

The physical properties of the reservoir rocks are good in term of the absolute values, and the difference of interlayers heterogeneity is minor with the heterogeneity coefficient of 1.21. But the variation of rock properties in the field is serious; the maximum and minimum permeability are 11.34 μm^2 and 0.44 μm^2 respectively.

Table 1. Reservoir and fluid characteristics of Jinglou Pilot

Reservoir depth (m)	358.0
Effective formation thickness (m)	5.45
Thickness ratio	0.61
Porosity (%)	32.7
Permeability (mm^2)	3.113
Oil saturation (%)	65
Reservoir temperature (°C)	30.7
Reservoir pressure (MPa)	3.0
Gas and oil ratio	4.65–5.60
Oil gravity (g/cm^3)	0.94–0.96
Oil viscosity (MPa·s)	16,111–21,445
Asphalt and resin content (%)	31.5–46.7
Sulfur content (%)	0.1–0.32
Paraffin content (%)	about 6
Pourpoint (°C)	0–8

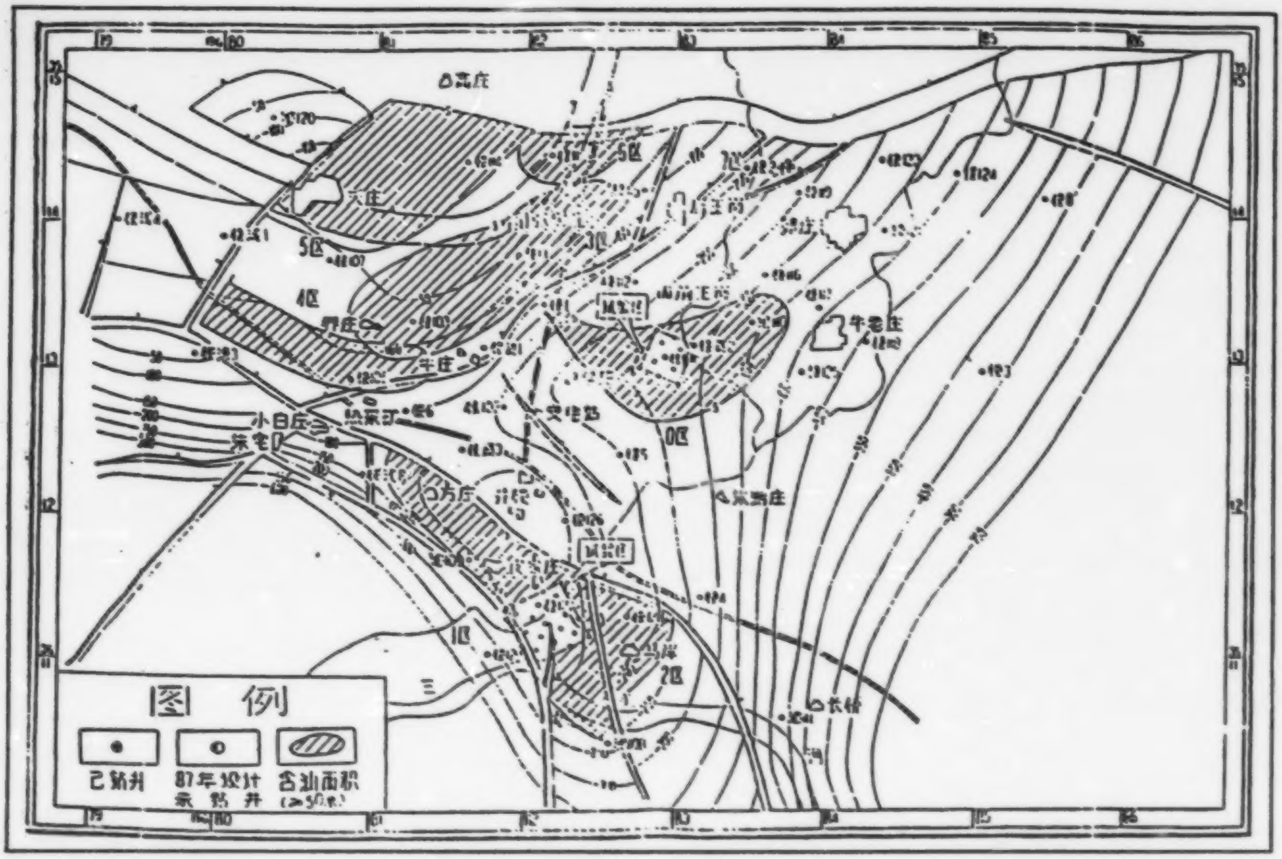

Figure 1. Structure map of Jinglou oilfield.

DESCRIPTION OF FIELD DEVELOPMENT

The steam injection pilot with 4 inverted 5-spot patterns (13 wells) was established in the Jinglou district. The distance between injector and producer is 100 meters; and the net pay in the pilot area averages 5.45 meters (21.1% of the thickness is greater than 9 m. and 38.5% less than 5 m.). Through several simulation and feasibility studies, the field-test started in 1987. During the testing period, a 3-D numerical model was used to investigate the distribution of pressure, temperature, and oil saturation at different cycles in the reservoir. From analysis of the field and simulation data, the results were utilized for further adjusting steaming operation. In the field practice however, the heat losses from such thin-bed formation and from the frequent well conversion are significant. Thus the same string with sucker rod pump was kept in hole during injection, and the pumping unit with variable radius was used to match the wide range of oil rates. Up to the end of April 1990, 68 steaming cycles had been conducted on 13 wells, and most of them had 5 cycles of operation. The cumulative steam injection and the cumulative steam-oil ratio were 68 460 tonnes and 0.54 respectively. The composite water cut was 13.2%, and 42.1% of the injected fluid was recovered. At the time, the oil recovery was 27.6% of OOIP and the average oil withdrawal rate was greater than 10% per year. And to this point, the pilot is ready to be converted for steam flooding.

Because of the thin and heterogeneous formation with high oil viscosity in the Jinglou pilot, the oil production by steam stimulation has the following characteristics:

1. *Production statistics.* According to the comparable statistics data, the producing time were 86.5, 89.5, and 112.7 days; and the oil productions per well were 665.5, 583.6, and 771.4 tonnes for the first three cycles respectively. By comparing this data with the oil production from thick-bed heavy oil reservoirs in other fields, the producing performance per cycle in the Jinglou pilot could be characterized as the production time is short and the oil output is low. However, there would be no difference if the said comparison is made based on the unit of net pay rather than based on the total net pay (Figure 2).
2. *Well production performance.* For oil production in the Jinglou pilot, the flowing time of the initial three cycles was 15.0 to 25.8 days, which shared in16.4% to 24.7% of the total cycle period; and contributed 32.1% to 39.19% of the total cycle oil production. However, 60.9% to 66.9% of the total oil was produced at the pumping stage, that participated in the total production cycle ranging from 75.2% to 83.6%.

According to the statistics data from 35 soaking cycles in these pilot wells, the exponential oil-rate decline was similar to those produced from the heavy oil reservoirs with a thick pay. But the magnitude of oil rate drop was larger than that of the latter. The decline curve has two sections as shown in Figure 3, in which the first part indicates the period with a significant oil rate decrease (74% per month), but that greatly diminished to 17% per month during the later production. In fact, the highest daily oil in the later period was only 2 tonnes per day, which is the abandonment oil rate.

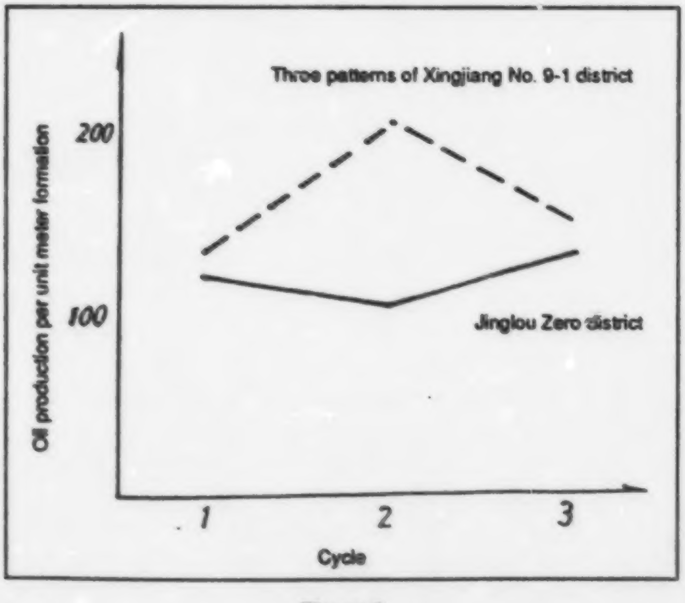

Figure 2.

3. *Well interference.* For most wells after the second cycle, serious well interference was experienced in this pilot. Steam injection into the structurally low wells often caused the production response in the highly structural wells. In viewing this situation, the injected steam frequently advanced from wells with low Kh to the high Kh wells (Figure 4). These respondent wells normally had good steaming and production history, or had possibly been fractured. From a preliminary analysis, two factors the pressure and temperature gradients during the injection period, and the reservoir heterogeneity are responsible for this problem. Up to now, 16 interference within 9 pairs of wells were observed in this pilot. The early interference generally occurred after 4 to 5 days of steam injection (maximum 9 days). Sometimes it took only one day. The interference basically resulted in an increase of temperature, water cut, and total liquid production on wells. Oil production at the early stage increased but decreased with time. When the interference factor was removed, the production condition on the respondent wells returned to the pre-interference situation, but the oil rate and well temperature increased somewhat. Because of well interference, it increased oil production by 1,550 tonnes and prolonged the production period by 146 days during the third cycle of steam stimulation.

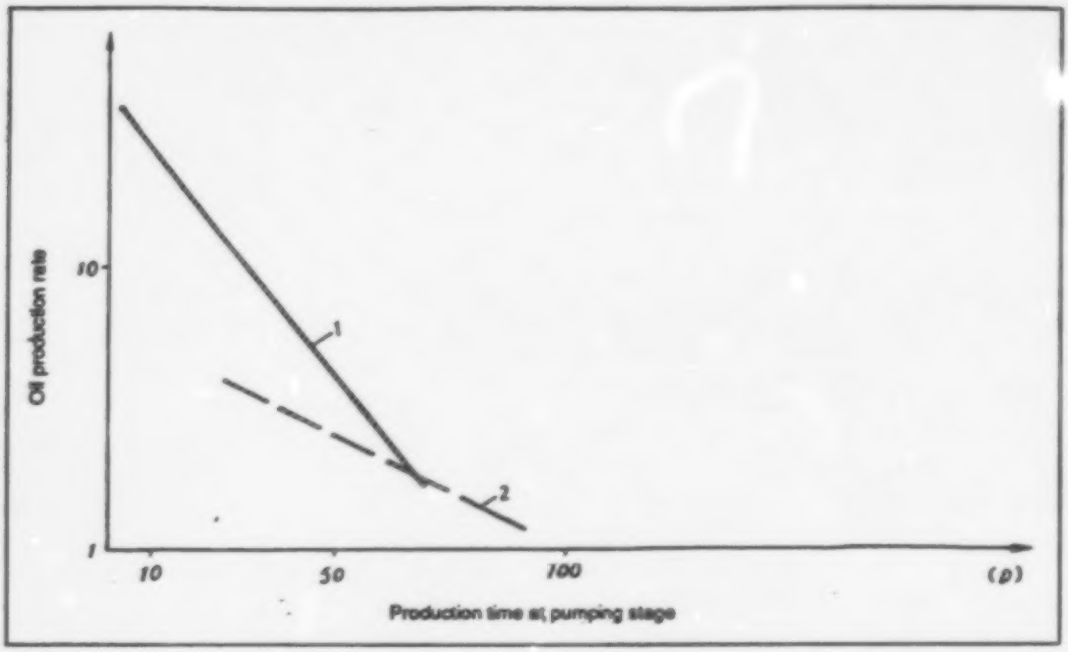

Figure 3. Production decline curve.

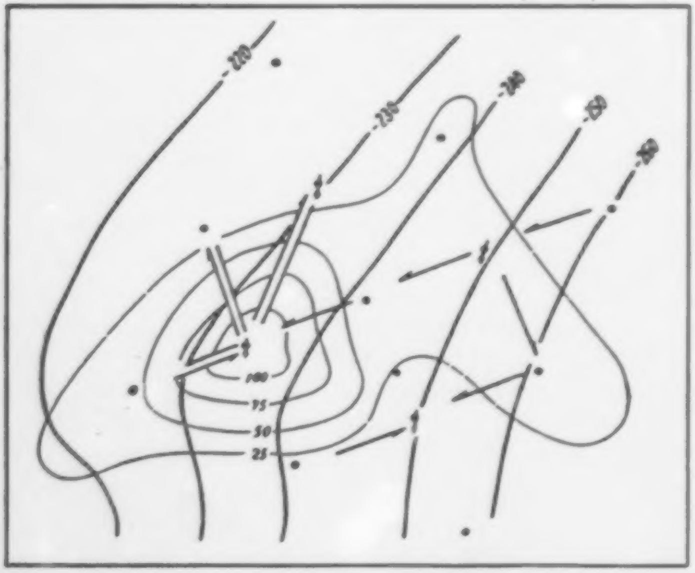

Figure 4. KH contour line and interference between wells sketch map in pilot ① in figure, arrowhead indicates the interference direction, and data indicates interference cycle.

PRACTICE OF TRACKING NUMERICAL SIMULATION FOR STEAM PILOT TESTS

Using steam injection to recover heavy oil is a new technique developed in the last twenty years. A great deal of information in this regard has been accumulated in the oil industry. However, in viewing the research and field records, there is not much data in regarding the development of a shallow, multiple thin-layer, extra heavy oil reservoirs. Therefore for Jinglou field reservoir feasibility studies and project development, we had to start from scratch. Based on our own field data from a few experimental wells, a numerical model was used for the initial study. The results indicated that ultimate oil recovery from steam injection in this field would be 32% of OOIP, in which,8% of this will be produced

Table 2. Average cycle and oil production per well

Oilfield	Cycle	Cycle production time (day)	Prod. time per meter formation (day)	Cycle oil production (ton)	Oil production per meter formation (ton)	Wells	Formation thickness (m)	Reservoir oil viscosity (mpa-s)
Jingiou	1	86.5	14.9	665.5	114.7			6000
Pilot	2	89.5	15.4	583.6	100.6	11	5.8	8000
area	3	112.7	19.4	771.4	133.0			
9-1	1	259.6	17.3	1917	127.8			
District	2	338.4	25.6	3015	201.0	15	15.0	1118
Karamay	3	261.3	17.4	2223	148.2	12		

Table 3. Flowing statistics for each cycle in pilot

Parameters	Flowing time (day)			Oil production at flowing stage			
Cycle	Range	Average	(%)	Flowing oil production per cycle	Average flowing oil production per well	(%)	Wells
1	1-37	15.0	16.4	2145	15.9	33.1	9
2	2-37	18.0	24.8	2920	14.5	37.2	11
3	7.7-61	25.8	21.3	3791	13.1	39.1	13
4	1.6-28	10.7	10.1	1144	21.4	33.0	5

by steam stimulation. The best approach is to maximize oil recovery by steam drive after two cycles of huff and puff operation. Thus, there would be no oil produced during the earlier two years of steam drive, and a "saddle" shape of the production curve would be shown on the field oil performance graph.

According to this prediction, the development program was undertaken and steam pilot was designed. From our field test, the total oil production from the first cycle operation on 13 wells reached 6.3% of OOIP; this is much better than the model prediction. Thus we believe that the input data used in the early numerical simulation was inadequate to represent the rock and fluids characteristics in this reservoir, since such figures are not easy to be determined accurately. This is especially true for reservoir heterogeneity and oil's PVT data at the high temperatures. From the field development point of view, an early reservoir simulation would not give us all the answers; rather, the model must be frequently modified based on field performance and further studies throughout the whole course of project development. Therefore, tracking numerical simulation should be used to enhance the predictability of reservoir performance. Through the combination of reservoir studies and the model results, the effectiveness of field development can be evaluated and predicted periodically.

Tracking Numerical Simulation

Because of the poor rock properties and the extra-heavy crude in this multiple thin-layer reservoir, if the development decision is made strictly based on the single well production, producing oil steam ratio, and the experience obtained from other successful thermal recovery projects, our resolution and confidence to conduct a steam injection pilot in the Jinglou field would be shaken. In fact, the actual field test resulted in 27.6% of OOIP from steam stimulation; this oil recovery was much better than the 8% predicted by the early reservoir simulation. According to this comparison and the economic evaluation, the Jinglou steam injection pilot was successful, which is due to the the following reasons:

a. *Further understanding the reservoir.* The earlier reservoir simulation predicted the oil recovery of about 8% of OOIP from steam stimulation. This compared with the actual result of 6.8% from the first cycle test was too pessimistic. By using our field data to rerun reservoir simulation, the rock and oil properties were adjusted during the history match. This time, the ultimate oil recovery by steam stimulation increased to 14.6% of OOIP in the pilot area, which is 6.6% better than that of the earlier result. In the explanations of this discrepancy, One believed that the reservoir permeability used for the early simulation was too low, since this parameter obtained from well logs interpretation was thought to be inaccurate. However the adjusted K value based on the match of actual field data in the later simulation increased by 4.5 times of the original input. This seems difficult to justify the reason of changes due to the already high permeability in the reservoir. The other suspected that the oil viscosity in the reservoir condition was thought too high, since no solution gas was assumed in this heavy crude. According to the history-match runs, the said solution GOR must be increased from 0 to 5 in order to match up the established field performance. As a result, the oil viscosity, as the input for the later simulation, was reduced to half of the previous values. Actually, this adjustment was proved by the laboratory data. That is the initial solution GOR in the Jinglou heavy crude ranging from 4.65 to 5.6 m^3/m^3. This figure was obtained from the PVT study of an oil sample produced in the flowback period of stimulation.

b. *Reducing heat losses during steam injection.* Based on the prediction of the earlier simulation, heat losses to the overlying and underneath strata is more than 50% of the total heat generated, and the effective heat absorbed in the producing zones is only about 30%. In order to tackle this problem, the tubing string with pump should not be pulled out during well conversion, this will not only save time but also reduce heat losses. In addition, the increase of steam injection rates and decrease of overall heat losses through the surface pipeline and tubing string could further improve the heating efficiency in the reservoir. From these approaches, the later numerical simulation showed that after three steaming cycles, the pipeline and wellbore heat losses would be 17% of the total heat generated; 31% of this heat will go to the overlying and underneath strata. Thus, the neat heat used for heating the oil bearing zones would increase form about 30% to 52%. The said heat losses to the overlying and underneath strata would further decrease with the increase of stimulation cycles (Figures 4-1 and 4-2).

c. *Improving reservoir performance prediction.* The producing performance from the thermal recovery wells is very sensitive to the tubing and reservoir temperatures. This is because the driving force is from heat, which reduces the oil viscosity to promote its flow. Oil production therefore seldom exhibits stable rates regardless if this happens in a single or a group of wells in any cycle or in any field. Therefore, determining the abandonment oil rate on wells in a producing cycle, this must be gauged by the existing reservoir situation correspondly. From which, one would have a better idea for next cycle operation. The statistics of production from 22 cycles on 9 wells as shown in Figure 5 indicate that the oil rate (Q_o) was linearly related with the wellhead temperature (T_c).

$$Q_o = 0.598 * T_c \, 11.5 \qquad r = 0.924$$

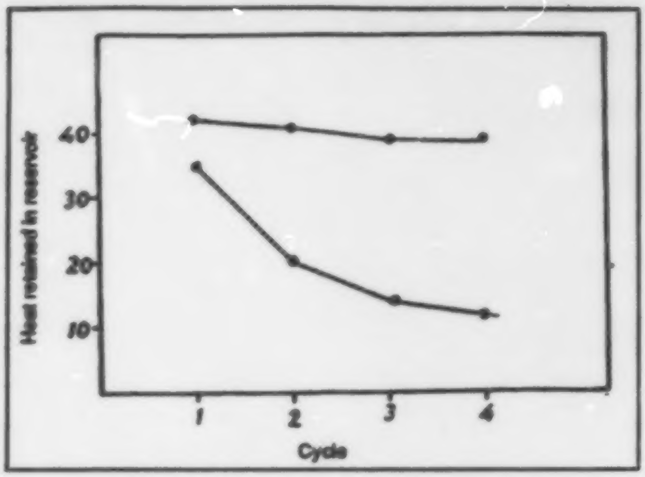

Figure 4-1. Change curve for the quantity.

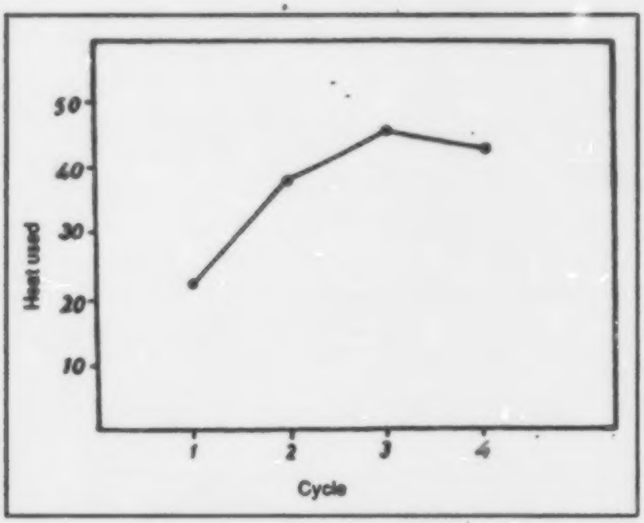

Figure 4-2. Heat usage changing curve.

The daily oil rate reached 10 tonnes when the wellhead temperature was higher than 40°C. The total oil produced in this period was about 70% of the cycle oil production. At the abandonment oil rate, the wellhead and the reservoir temperatures exhibited the following relationship:

$$T_r = 16.1 + 0.793 * T_c \qquad r = 0.91$$

where T_r is the reservoir temperature, and r is the correlation coefficient.

Assuming K and h in the transmissibility coefficient (Kh/u) are independent of the temperature changes, thus only the crude viscosity, which is reduced by the heat from steam, would help increase oil mobility. From this, the true oil production in the reservoir could be estimated approximately based on:

$$Q_t = Q_o * u_c/u_r$$

When wellhead temperature (Tc) is 40°C, reservoir temperature (T_r) is 47.8°C, oil viscosity at reservoir condition (u_r) obtained from the viscosity-temperature curve is 700 mPa-s, and wellhead oil rate (Q_o) was 12.4 tonnes/day. So the true oil production (Q_t) would be 8.9 tonnes/day and the ratio of Q_t to Q_o is 0.72, which is the same as the transport difference in this pilot.

When the oil production (Q_o) lowered to the abandonment rate of 2 tonnes/day; from the mentioned equations, the reservoir temperature should be around 34°C, at which the oil viscosity would be 4,000 mPa·s. These values are nearly the same as those of the temperature and associated oil viscosity in the initial reservoir conditions. Thus, as long as we could maintain the reservoir temperature of 5°C above the initial figure, and oil viscosity less than 4,000 mPa·s in the Jinglou reservoir, certain daily oil production would be achieved.

In the early reservoir simulation of the pilot test, it was difficult to match the distribution of pressure, temperature and fluid saturation in the reservoir, because of limited reservoir and production data. Thus the timing of scheme conversion from stimulation to steam drive was mainly decided by the oil-steam ratio (OSR) and the oil abandonment rate from the forecasts of simulation study. Which indicated that the best operation strategy converting the huff and puff process to steam drive after two cycles of stimulation would result in an ultimate oil recovery of 40% of OOIP with a cumulative OSR of 0.266. In the actual

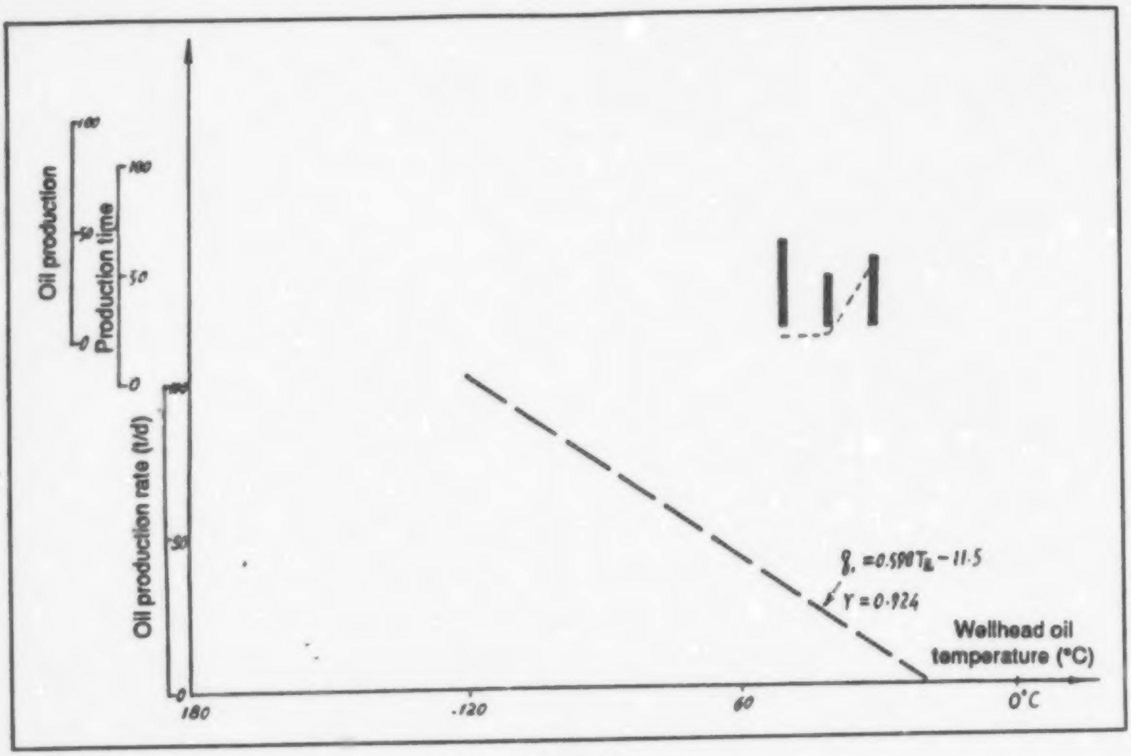

Figure 5.

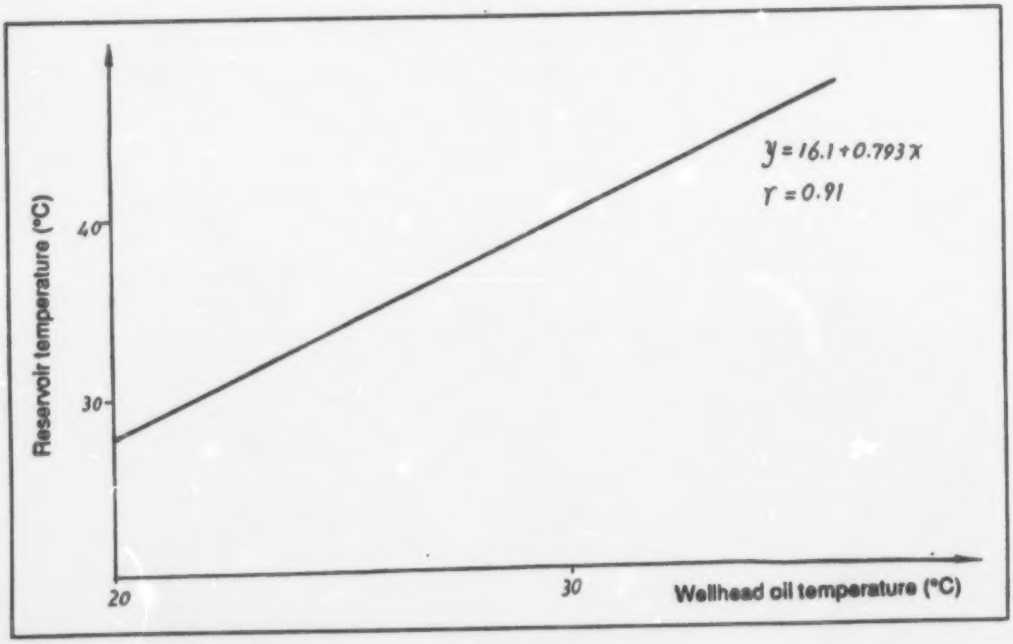

Figure 6.

field practice however, after two cycles of stimulation, the reservoir heterogeneity caused problems in terms of pressure, temperature and fluid saturation distributions in the Jinglou pilot. This is due to the early reservoir simulation, which used only 1/4 or 1/8 of the pilot wells for model study; such inputs with limited data simply can not describe the overall reservoir. Therefore, the detailed, full-scale simulation to emphasize the distribution match of pressure, temperature, and fluid saturation in the reservoir would give us better predictions. The stage tracking numerical simulation must be done periodically.

The results of the earlier numerical simulation are presented in Figures 7, 8, and 9, which show the distributions of temperature and oil saturation after two steaming cycles in the Jinglou pilot. From these, the radially heated zone away from the pilot wells was no more than 25 meters, and it was merely about 20 meters around the central evaluation well. After steam drive however, 4 of 9 pilot wells responded effectively, the other 5 wells exhibited high residual oil saturation up to 40% in the nearby area, and the formation temperature was only about 50°C. All of these indicate that heat distribution before steam drive was not uniform in the reservoir, and this resulted in a low volumetric sweep efficiency and a low oil recovery. Therefore, a further study

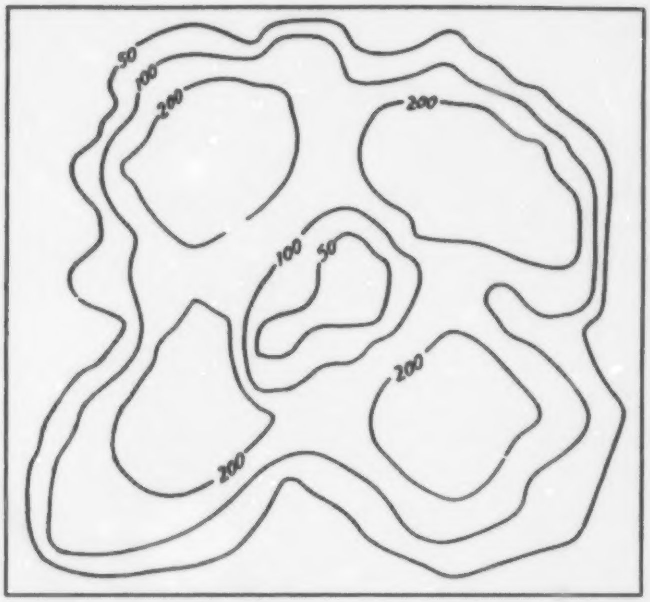

Figure 8. Temperature contour (°C).

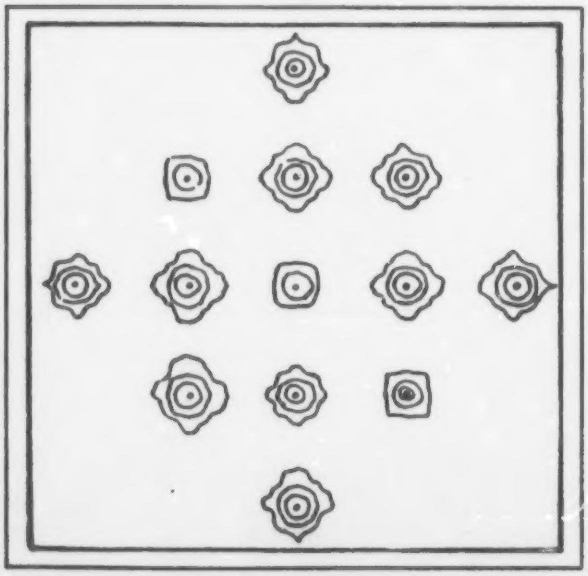

Figure 7. Temperature distribution at end of steam soak.

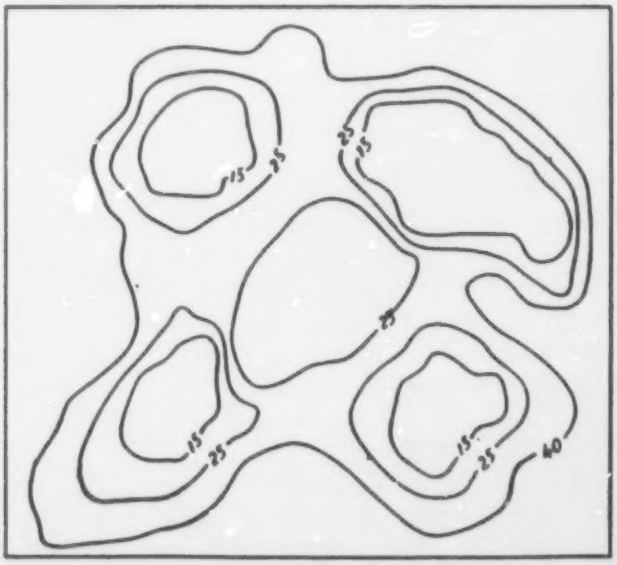

Figure 9. Oil saturation contour (0/0).

using tracking numerical simulation was conducted for this pilot. The results suggested that increasing stimulation cycles, which enlarges the heating radius from wells, improves the hydraulic communication, evens the temperature and pressure distribution, and heightens the hot oil mobility to a certain degree in the reservoir, would enhance oil recovery performance in this pilot. By doing this, the said study predicted that the ultimate oil recovery could reach 52% of OOIP with cumulative OSR of 0.231. Figures 10, 11, show the residual oil, remaining temperature after the end of the proposed steam drive, and Figure 12 presents the current heat communication diagram in this pilot. According to the forecasts, 8 of 9 pilot wells would respond to this steam drive very well. Finally, the residual oil saturation would be less than 20% and the reservoir temperature might reach 100°C in the pilot area.

Optimization of Steam Injection Parameters

Because the type of heavy oil reservoirs in nature are different, the development approaches must be distinct, so the well completion, surface facilities, steam quality, injection rate, and heat losses are unlikely the same. Accordingly, it is unfair to judge whether it was successful in a steam injection project, strictly based on the injection rate and overall oil-steam ratio. Instead, the actual enthalpy input into reservoir must be emphasized by optimizing the steam injection parameters in the field practice.

a. ***Optimization of heat injection rate.*** Based on an analysis of the first cycle injection and production data from 13 wells in the Jinglou pilot, the length of the production period was related to the amount of the total heat injection. In order to effectively evaluate the steam injection and response in the pilot wells, the total injected heat was converted into the basis of heat per unit thickness of reservoir. Figure 14 shows the relationship between the cycle oil recovery and the the heat injection per unit thickness. In this graph, the initial slope of the first straight line is steep, and the second one flattens out. The intersection of the two straight lines corresponds to 60 million kcal/m and 200 tonnes/m of oil production. This amount of the heat input is obviously the optimum injection rate in this

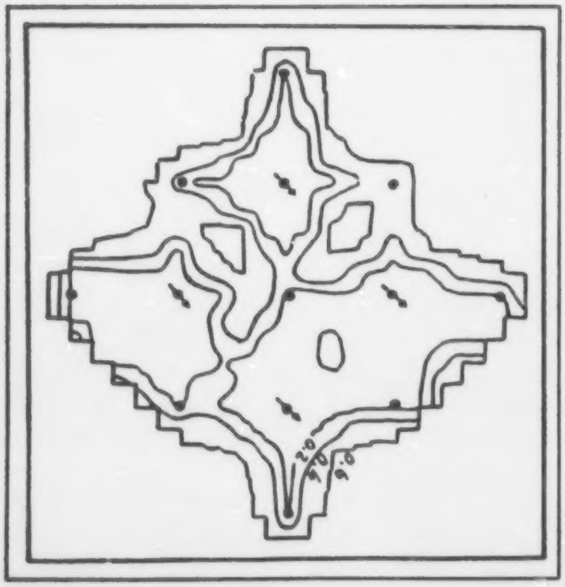

Figure 10. Oil saturation distribution at the end of steamflood (Project 5).

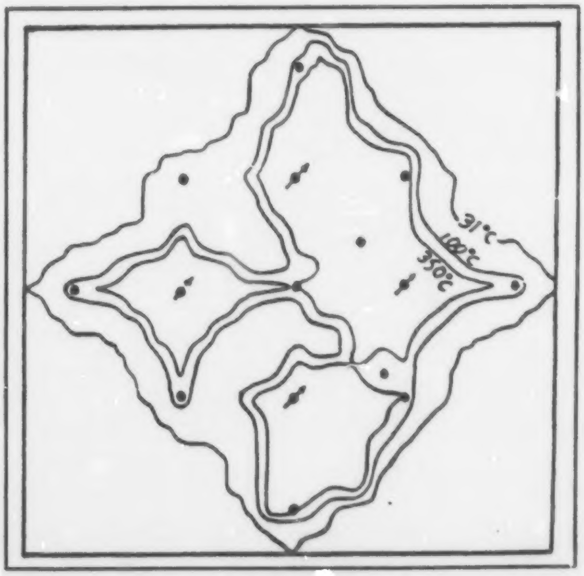

Figure 11. Temperature distribution at the end of steamflood (Project 5).

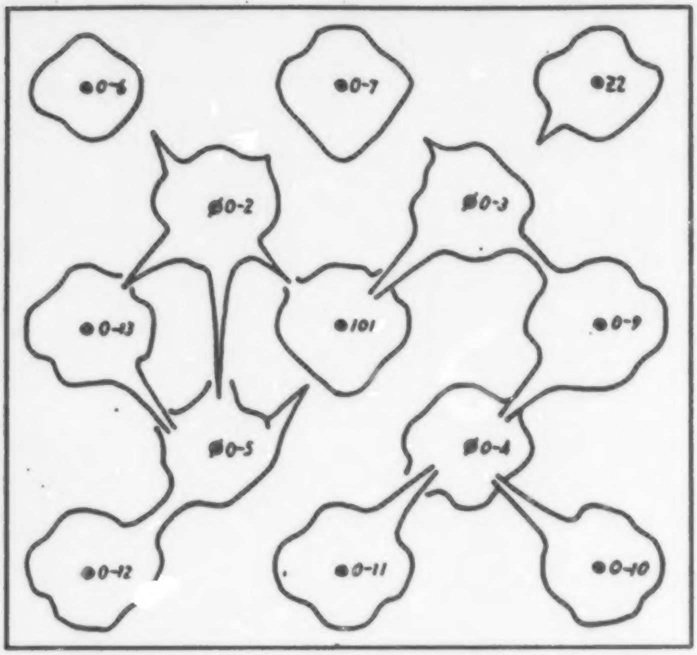

Figure 12. The current heat communication diagram in pilot.

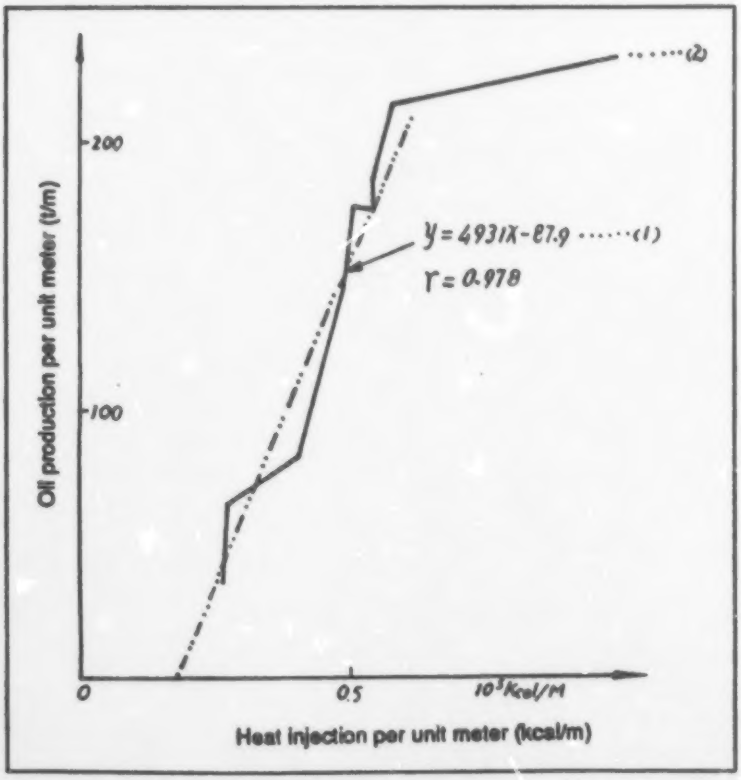

Figure 13.

reservoir. In considering the reservoir properties, the capability of steam boiler (produced steam quality only 40–50%), and the overall heat losses, the selected optimum rate for the first cycle injection was 130 tonnes/m. For the subsequent cycles of steaming operation, the increase of 15% of the previous injection rate was required.

b. ***Steam quality — the key for oil recovery.*** The heavy oil recovery by steam injection is related to the effective heat absorbed in the productive zones. The more heat injected, the more oil produced. Since the input of heat per unit of the injected mass is controlled by steam quality, which, in fact, really governs the success or failure of a steam injection project. The statistics of the Jinglou pilot data indicates that the increase of steam quality for steam injection has increased or improved:

- Peak oil production rate (Figure 15)
- Oil production per unit thickness in wells (Figure 16)
- Oil-steam ratio (Figure 16)
- Steam zone expansion and oil recovery

For thick (over 10 meters) heavy oil reservoirs, however, the injection of high quality steam with a high specific volume and low viscosity might result in a steam overriding problem in the reservoir. Consequently, this effect would inhibit steam zone expansion, reduce volumetric sweep efficiency, and decrease oil recovery. Therefore in general, an optimum steam quality is required for steam injection in a specific heavy oil reservoir. Fortunately, for steaming such thin-layer heavy oil reservoir in the Jinglou field, the chance of having steam overriding problem is insignificant. This conclusion was also confirmed by the results of reservoir

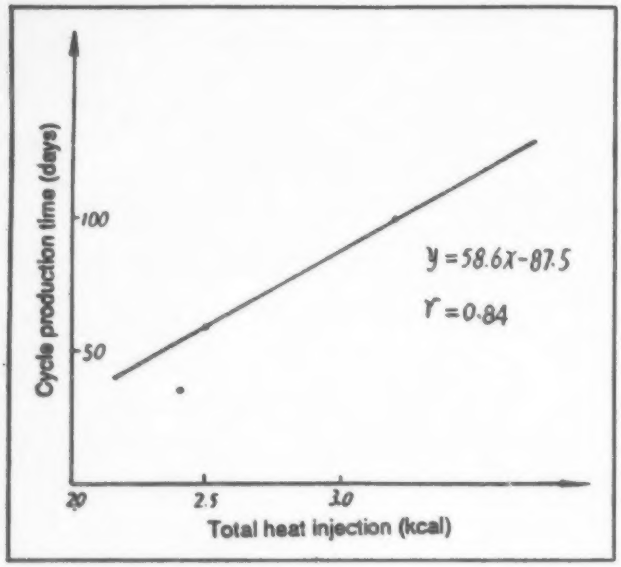

Figure 14.

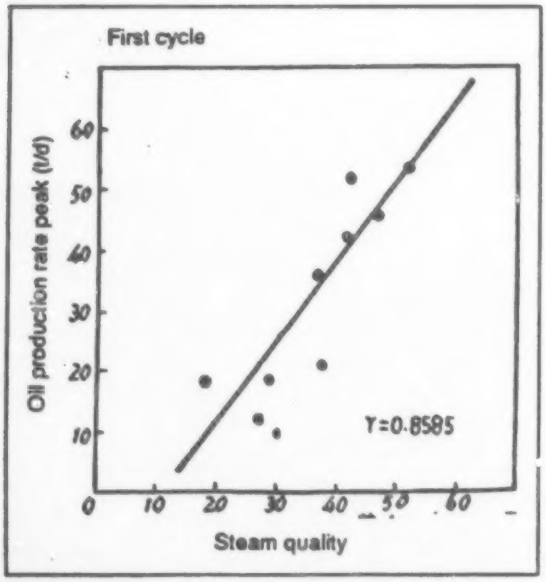

Figure 15. The effect of steam injection parameters on steam soak.

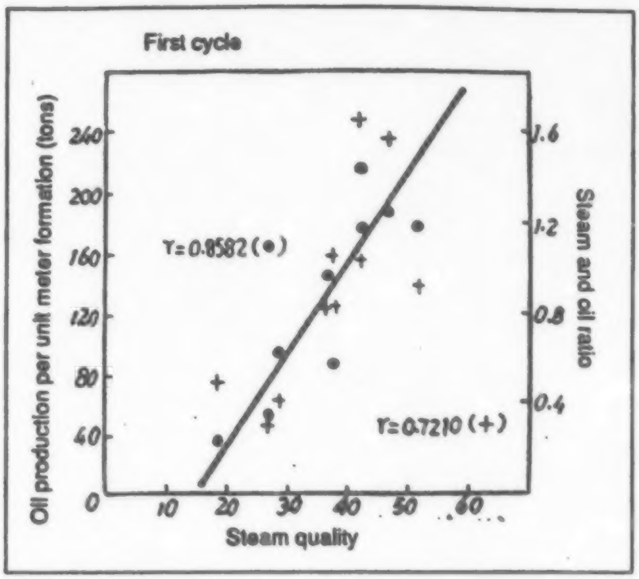

Figure 16. The effect of steam injection parameters on steam soak.

simulation study, which indicated that injecting high quality steam in this reservoir would have high oil producing rates and higher oil recovery (Figure 17).

In the initial stage of Jinglou pilot test, steam quality was very low (only 10% at bottomhole) due to the capability of steam boiler used. The injected hot water developed a high water saturation region around the injection wells and trapped large amount of water. Since this fluid could not be removed in the producing cycle, the accumulated water blocked steam injection and raised wellbore injection pressure substantially. In the third cycle, more injected water in the reservoir resulted in a high differential pressure, an expending water zone, and finally hot water breakthrough. After the injection scheme was converted to stem drive, the channeling steam occurred at the bottom of reservoir, in which, the existing hot water zone offered the flow paths with low resistance for steam. Therefore, the limited

Table 4.

Steam quality (%)	0	5	10	20	32	50	78
Steam injection intensity (%)	200	180	163	140	130	95	70

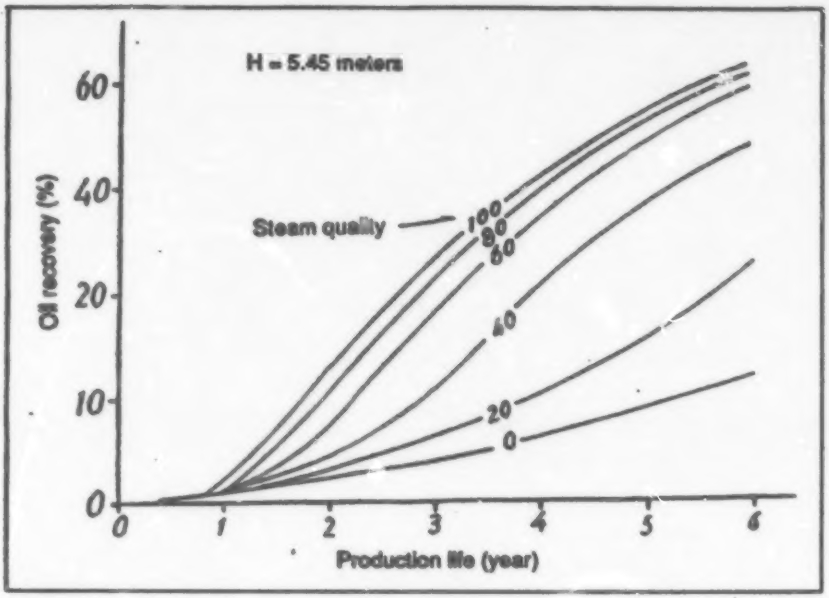

Figure 17.

Table 5.

Oilfield Item	9-3 District Karamay	9-6 District Karamay	Jinglou Karamay
Cycles	3	3	3
Reservoir thickness (meter)	10.2	9.5	5.45
Oil viscosity4000 (mpa·s)	11,264-30,000	16,000-24,000	
Oil/steam ratio	0.71	0.59	0.75
Oil/heat ratio (g/kcal)	1.3	1.1	1.83

steam zone expansion led to a serious problem with poor sweep efficiency and low oil recovery (Figure 18). In order to improve the steam drive efficiency in the Jinglou reservoir, the injection with high steam quality must be emphasized, and removing the trapped fluid or reducing reservoir pressure must be done during steam stimulation. This is the key to enhance the oil recovery in this pilot.

c. ***Field performance.*** In the Jinglou pilot test, all steam injection parameters were optimized by the results of reservoir simulation study. Using these for actual practice, the field data from three cycle of steam stimulation indicated that both OSR and oil/heat ratio were higher than those from other steam simulation projects.

Conversion from Steam Stimulation to Steam Drive

By using the optimized injection parameters, reducing heat losses through pipeline and wellbore, and increasing reservoir heating efficiency for steam stimulation in the Jinglou pilot, the cumulative oil recovery after three cycles operation reached 17.9% of OOIP in this reservoir. In respect of the scheme conversion from stimulation to steam drive, the timing is so important and must be decided based on the results from further reservoir simulation study. Considering the areal permeability variations in this pilot, the production history from 13 wells of four well groups were used for history match, the matched results were adopted for prediction runs to determine the optimum timing of conversion. In reviewing the outputs, the time of conversion actually decides the initial conditions in the reservoir for steam drive, such as temperature distribution, hydraulic communication, and oil mobility. The overall steam flooding performance and oil recovery are impressed by these factors. To sum up, the best timing for conversion is when the reservoir exhibits a certain high temperature with a fair communication among wells, and good oil mobility.

Data in Table 6 derived from the said simulation study shows two cases of steam drive performance based on different timing of scheme conversion. The results from a premature conversion are presented in case 1, in which, the reservoir after two cycles of

Table 6.

Time		Steamflooding before heat communication: Oil production (1 x 10^4 t)	Steamflooding before heat communication: Fraction of total oil production (%)	Steamflooding after heat communication: Oil production (1 x 104 t)	Steamflooding after heat communication: Fraction of total oil production (%)
stimulation (cycle)	I	0.598	13.6	0.548	7.34
	II	0.488	11.1	0.511	6.84
	III	/	/	0.600	8.04
steamdrive (year)	1	0.1108	2.5	1.7348	19.5
	2	0.3314	7.6	1.7648	23.6
	3	2.8516	65.1	1.3884	18.6
	4			0.9193	12.3
Total		4.3798	Oil recovery 40%	7.4653	Oil recovery 54%

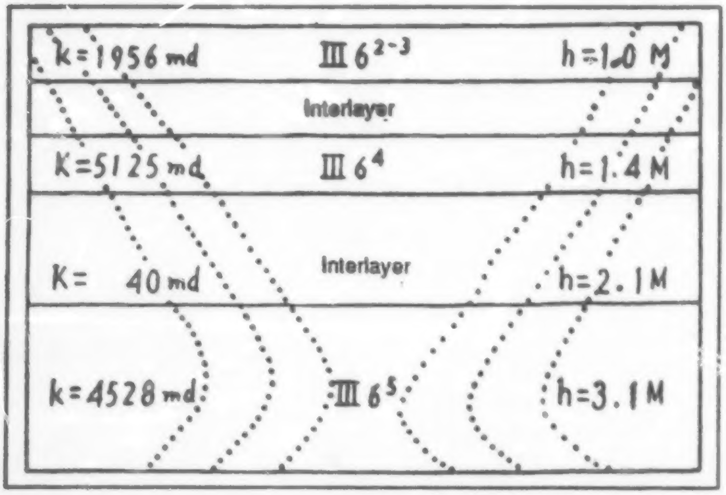

Figure 18.

stimulation was not ready, in terms of the mentioned factors, for steam drive. The local cold oil simply blocked steam flow in the reservoir. This caused steam channeling and coning problems, that seriously deteriorated production performance of steam drive. For instance, the low oil rates for two years followed by a production jump due to steam breakthrough in the third year (86.6% of the total oil produced in the flooding period or 65.1% of the entire project oil production), demonstrate an abnormal oil production response to steam drive. This strange performance, if this had actually occurred, would lead to a lot of problems in the field practice. On the contrary, the relatively stable production history is shown in case 2 (Table 6), for which, the injection scheme was converted after three cycles of steam stimulation in this pilot. The ultimate oil recovery reached 52% of OOIP in this case.

During the tracking numerical simulation for steam injection in the Jinglou pilot, we found that grid orientation in the said study affected the steam flooding results seriously. For the output from the models with diagonal grid and parallel grid, the difference of the high OSR period (no steam breakthrough) was more than three times between them. In steam drive, the viscosity of cold oil in front of the steam zone is about 10,000 mPa·s, but steam viscosity is only 0.01 mPa·s. If diagonal grid is adopted in numerical simulation, this high steam/oil mobility ratio (more than 100,000) would result in a fast steam moving, low heat usage, and high heat losses in the model. This irregular steam movement limits the heating area (low sweep efficiency) and lessen oil production. The production performance would be:

- no oil produced initially by steam drive
- a period with fast increasing oil rate (after steam breakthrough)
- followed by certain time with quickly oil rate decline

Such situation, however, was not observed in the field, on the contrary, the Jinglou pilot performance was matched by using the model with parallel grid. The results of these studies are presented in Figure 19. Therefore, for simulating a heavy oil reservoir with oil viscosity greater than 1,000 mPa·s, the steam model with parallel grid should be used.

Evaluation of the Jinglou Steam Injection Project

The evaluation of the Jinglou steam injection project was carried out based on the combining results of the tracking numerical simulation and reservoir performance analysis. The high lights of this project are summarized as follows:

- High heating efficiency could be achieved in steam stimulation by reducing heat losses through pipeline and wellbore, eliminating well conversion time, and using the variable radius pumps. As a result, the predicted heating efficiency would increase from about 30% to 52% of the generated heat. For a high oil price in the future, this efficiency could further be improved.
- In order to tackle the low steam quality problem, the amount of the effective heat-injection in the reservoir was guided by using the optimized injection parameters. This was done based on the combined information from the numerical simulation and from field practice. As a result, the oil to steam ratio and oil to heat ratio during the period of steam stimulation reached to 0.54 and 1.83 g/K cal respectively. This performance is equal or better than those observed in the other similar heavy oil reservoirs.
- If an evaluation is based on the unit of reservoir thickness, the steam stimulation performance in the Jinglou pilot is surely better than that from those thick heavy oil reservoirs. The average thickness of the Jinglou reservoir is about 5 meters. Yet it produced 530 tonnes/meter of oil by steam stimulation, and resulted in an oil recovery of 27.6% of OOIP, and recovery rate of more than 10% per year of the recoverable oil.
- During the three years steam stimulation test in the Jinglou pilot, the high and fast oil recovery was observed in the field practice. Thus the overall costs (nearly the same as those in the thick heavy oil reservoirs) were low, the rate of return was high, and the objective of commercial operation to recover heavy oil in this field is achieved (Table 7).

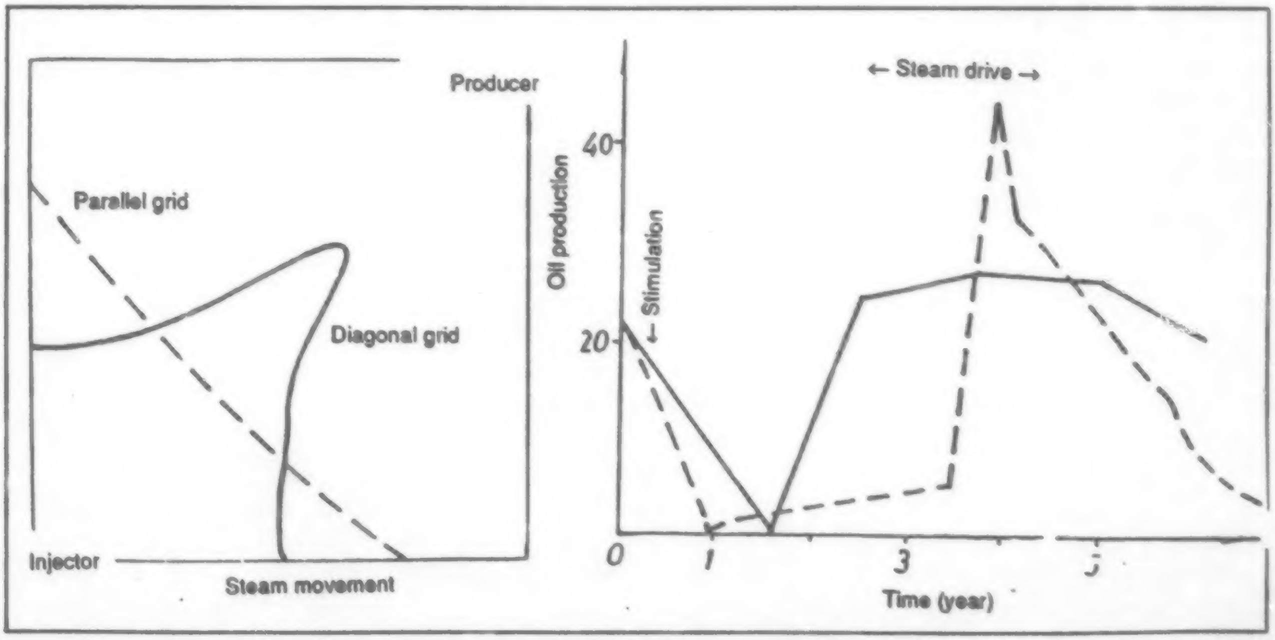

Figure 19. The effect of grid orientation on steam injection results.

Table 7. Results of economic evaluation

Item Oil price (Yuan/ton)	Construction investment capital (x 10^4)	Cost of production (x 10^4)	Cumulative output value (x 10^4)	Net present value (x 10^4)	Average cost of oil (Yuan/ton)	Pay out period (year)	Net present value per unit well (x 10^4/well)
152	527.4	867.8	511.4	–547.04	260	/	–42.1
295	527.4	867.8	992.5	–198.41	260	/	–15.3
485	527.4	867.8	1631.8	264.82	260	1.4	+20.4

CONCLUSION

Through three years of steam stimulation pilot tests in the Jinglou thin-layer extra-heavy oil reservoir, we conclude that the pilot development for thermal oil recovery is a process not only to further understanding the reservoir step by step, but also to find out the rules for optimizing the operation parameters. We believe that the tracking numerical simulation technique is a useful tool for economically and effectively to develop some demanding heavy oil projects.

HEAVY OIL PRODUCTION IMPROVEMENT THROUGH DOWNHOLE EMULSIFICATION

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ABSTRACT

Pumping viscous heavy crudes, especially those produced by fireflood operations, can pose serious challenges. Rod fall problems, slow pumping rates and low pumping efficiencies are often the result and oil production could be reduced significantly.

This paper reviews recent work on the feasibility of improving pumping capabilities and, thus, production by the downhole generation of low-viscosity oil-in-water emulsions with the aid of an injected surfactant solution.

In laboratory studies various heavy crudes were emulsified using a wide range of surfactants (emulsifiers). It was found that all crudes could be emulsified, but the ease of emulsification and the stability and viscosity of the emulsions were primarily determined by emulsifier type and concentration. The presence of sand destabilized the oil-in-water emulsions, however, adequate stabilities could still be achieved with certain surfactants.

The concept was tested in the field during 1986–87 by Norcen Energy Resources at their Bodo fireflood project. A single-well test was conducted, employing a hollow sucker rod and a diluent tubing pump for the injection of the surfactant solution. Based on laboratory evaluations, SRCK-1 surfactant was selected for the test as it produced suitable emulsions. Results were immediate and very encouraging. Rod fall problems diminished, the pumping rate and efficiency improved and the production climbed by a factor of about seven. Subsequent implementation of the process in other wells led to similar results.

INTRODUCTION

Pumping high-viscosity heavy oils is a difficult task under normal primary production operations. However, the formation of w/o emulsions during the operation of a fireflood can cause the viscosity to further increase and, hence, the problems can be amplified significantly. The consequences are usually high fluid levels, rod fall problems, slow pumping speeds and much reduced oil production.

In order to overcome these problems and increase production, diluents consisting of light hydrocarbons have been used to reduce oil viscosity and improve well productivities. The diluent is commonly injected downhole to improve the pumping efficiency and decrease the viscosity of the crude in the tubing and flow lines. Occasionally, heat stimulation is used to achieve these goals.

An alternative method of improving the production of viscous crudes is to create oil-in-water (o/w) emulsions downhole. The significantly lower viscosity of these water-continuous-emulsions may increase pumping efficiencies and reduce the viscous drag on sucker rods and the rotating shafts of screw pumps. Rod fall may improve, higher pumping rates may be achieved, and oil production will likely increase. The process also may make the check valves of downhole pumps water-wet. This will minimize sand adhesion to these valves, which in turn would result in a more consistent production.

As implied above, an important application of downhole emulsification may be found in fireflood operations, where the production fluids frequently consist of highly viscous water-in-oil (w/o) emulsions. Recent laboratory studies and field tests on the downhole emulsification process are reviewed in this paper.

LABORATORY STUDIES

A laboratory study, jointly sponsored by Texaco Canada and CANMET/EMR and carried out by the Saskatchewan Research Council, was undertaken to evaluate the technical feasibility of emulsifying two Texaco Canada Frog Lake primary wellhead crudes and a Texaco Canada Lone Rock steamflood crude, and to assess sand toleration by the Frog Lake crudes.[1] Characteristics of the three heavy crudes investigated in this study are given in Table 1.

Procedures

Using a 2:1 (by volume) mixing ratio, the wellhead w/o emulsions were emulsified in brine, which contained an o/w emulsifier. A range of eight different, commercially-available surfactant/emulsifiers (Petrofirm HO Flow, Tretolite CF-4W and PD-57, BASF Pluronic P-85, SRCK-1, SRCK-8, Pfizer F-2, and Pfizer PD-57, BASF Pluronic P-85, SRCK-1, SRCK-8, Pfizer F-2, and Pfizer F-10) was evaluated at concentrations between 250–2000 ppm. Immediately after preparation, the viscosity of the fresh o/w emulsion was measured using Brookfield viscometer. The emulsion was then placed in a bottle or graduated cylinder to determine its stability, which was accomplished by measuring the time it took for the water to break out and the original w/o emulsion to reappear. The effect of sand on o/w emulsion stability was studied by using synthetic wellhead emulsions with increased sand concentrations (2–15% v/v). Rapid sand dropout rates are undesirable since they can lead to potential problems with the sanding of downhole pumps.

Because of concerns that the presence of the o/w emulsifiers used for downhole emulsification might affect the operation of existing field treatment facilities, compatibility tests were performed in the laboratory to ensure that these emulsifiers were compatible with the demulsifiers used in the treatment plants. These tests involved performing standard bottle tests with the field demulsifier on the as-received wellhead emulsion and on the w/o emulsion that forms after the artificial o/w emulsion had separated. Any incompatibility between the emulsifier and the demulsifier would result in a final BS&W (Basic Sediment and Water) content of the converted and treated emulsion which would be somewhat higher than that of the original, treated emulsion.

Laboratory Results

All three crudes could be emulsified, but the ease of emulsification, the viscosity of the fresh emulsions and their stability were determined by a combination of wellhead emulsion characteristics, emulsifier type and concentration. As indicated by the Frog Lake 8-13 data in Table 2, the series of emulsifiers spanned a wide range, with the poorly water-wetting Petrofirm HO Flow emulsifier at one end, followed by the two Tretolite emulsifiers. These three emulsifiers produced rather unstable emulsions, which consisted of visually large oil drops and required high emulsifier concentrations (2000 ppm). The viscosities of these emulsions remained fairly high (Table 5). The two SRCK emulsifiers formed a group in the middle; they were moderately water-wetting and produced stable o/w emulsions with small oil droplets

Table 1. Characteristics of the Frog Lake and Lone Rock crude oils studied

Well	Formation	Formation temperature (°C)	Crude oil viscosity (mPa·s)	BS&W* (vol%)		TDS of brine (ppm)
Frog Lake				*W*	*S*	
8-13-57-2 W4M	McLaren	22-23°C	24,019	0	0.4	71,354
14-6-57-1	Waseca	22-23°C	12,664	2.6	0.3	77,226
Lone Rock						
B5-14-47-27 W3M		20°C	3,810	54	0	82,094

*W: water; S: solids

Table 2. O/W emulsion stabilities of Texaco Frog Lake wellhead crude (8-13-57-2 W4M) with various emulsifiers

Emulsifier *(ppm)		Water dropout (vol%) at room temperature							BS&W (vol%) after 24 h
		5 min	30 min	1 h	2 h	3 h	4 h	24 h	W
HO flow[a]	2000	–	18	20	20	20	20	20	8
	1000	–	20	20	20	25	25	25	
	500	25	30	30	30	30	30	30	
	250	w/o							
HO flow (Texaco)	1000	5	20	20	–	–	20	–	
Tretolite CF–4W[b]	2000	–	20	20	20	22	22	22	
	1000	–	20	25	25	25	25	25	
	500	20	25	30	30	30	30	30	
Tretolite PD–57[b]	2000	–	15	19	20	20	20	20	
	1000	15	20	22	22	22	22	22	
	500	20	25	25	25	25	25	25	
Pluronic P–85[c]	2000	–	3	8	10	15	15	20	
	1000	–	5	8	15	–	–	22	
	500	–	20	22	25	–	–	25	
SRCK–1[d]	2000	–	5	15	18	20	20	20	8
	1000	–	20	25	25	25	25	25	
	500	w/o							
	250	w/o							
SRCK–8[d]	2000	–	3	5	10	15	15	20	
	1000	–	22	25	25	30	30	30	
	500	–	25	30	30	30	30	30	
Flothin F–2[e]	2000	–	3	3	5	5	8	18	14
	1000	–	3	3	8	15	15	18	
	750	–	15	20	22	25	25	25	
	500	20	22	25	25	25	25	25	
Flothin F–10[a]	2000	–	5	7	–	15	–	20	
	1000	–	3	5	10	15	15	20	
	500	w/o							

*Manufactured by: [a]Petrofirm; [b]Petrolite; [c]BASF; [d]Hart; [e]Pfizer

and much lower viscosities, especially at higher concentrations (1000–2000 ppm). BASF Pluronic P-85 formed the transition to the other end of the range, where the two Pfizer Flothin emulsifiers were found. These three surfactants were fairly good (P-85) to excellent water-wetting (Flothin) and produced excellent, stable emulsions with small oil droplets and low viscosities at lower concentrations (1000 ppm or less). The characteristics of the Frog Lake 14-6 and Lone Rock o/w emulsions (Tables 3, 4, 6 and 7) generally exhibited the same features as described above, however, there was a general trend toward lower stabilities. The much lower Lone Rock emulsion stability can be attributed to the lower density of the Lone Rock crude.

The compatibility tests showed that, regardless of the emulsifier used, the emulsification process left some residual water in the low-water-content Frog Lake crudes, which could not be removed by the demulsifier used in the field (Champion 888X). However, the situation with the high-water-content Lone Rock crude was quite different. The emulsifier SRCK-1 exhibited a unique feature, observed at numerous previous occasions, namely the capability to cause the water originally entrained in the wellhead crude to drop out following o/w emulsification. Subsequent treatment with Champion 888X then reduced the water content to a level similar to that of unconverted and treated crude (~1.0% final BS&W). In contrast, both HO Flow (final BS&W 7%) and,

Table 3. O/W emulsion stabilities of Texaco Frog Lake wellhead crude (14-6-57-1 W4M) with selected emulsifiers

Emulsifier *(ppm)		Water dropout (vol%) at room temperature							BS&W (vol%) after 24 h
		5 min	30 min	1 h	2 h	3 h	4 h	24 h	W
HO flow	2000	15	20	22	23	23	–	23	11
	1000	20	20	22	25	25	25	25	
	500	25	30	30	30	30	30	30	
	250	w/o							
SRCK–1	2000	10	15	20	20	–	–	23	8
	1000	15	22	25	25	25	–	25	
	500	w/o							
Flothin F–2	2000	2	3	3	4	5	10	18	24
	1000	5	15	18	20	20	20	25	
	500	10	22	25	25	30	30	30	

Table 4. O/W emulsion stabilities of Texaco Lone Rock wellhead crude (B5-14-47-27 W3M) with selected emulsifiers

Emulsifier *(ppm)		Water dropout (vol%) at room temperature							BS&W (vol%) after 24 h
		5 min	30 min	1 h	2 h	3 h	4 h	24 h	W
HO flow	2000	20	22	22	22	22	–	25	50
	1000	20	20	25	25	25	25	30	
	500	25	30	30	30	30	35	35	
SRCK–1	2000	40	50	53	55	–	–	58	26
	1000	45	50	55	58	–	–	58	
	500	42	42	42	42	–	–	42	
Flothin F–2	2000	8	20	20	22	25	25	30	48
	1000	20	25	30	33	35	35	35	
	500	30	30	35	35	37	37	37	

Table 5. O/W emulsion viscosities of Texaco Frog Lake (McLaren) wellhead crude (8-13-57-2 W4M), using various emulsifiers at three concentrations

RPM	Viscosity (mPa·s) at 22°C											
	HO flow (ppm)			Pd-57 (ppm)		SRC-K1 (ppm)		P-85 (ppm)		Flothin F-2 (ppm)		
	200	1000	2000	1000	500	1000	2000	1000	500	750	1000	2000
0.5	12730	13890	15620	6590	41100	7270	1360	1140	21990	3640	680	340
1.0	14520		15330		35040		965		19090	2960		170
2.5								14120				
5	11030	9660	7620				475				135	
10				2450		710	305	140		850	125	130
50												
100						95		60		45	65	

***Table 6.** O/W emulsion viscosities of Texaco Frog Lake (Waseca) wellhead crude (14-6-57-1 W4M), using selected emulsifiers at three concentrations*

RPM	Viscosity (mPa·s) at 22°C								
	HO flow (ppm)			SRC-K1 (ppm)			Flothin F-2 (ppm)		
	500	1000	2000	500	1000	2000	500	1000	2000
0.5	13310	4320	4210	w/o	2840	680	17360	7390	115
1.0	11570	3580	3410		1820	450	8130	4550	115
2.5									
5	9210								
10		2930	2330		560	180	3130	450	170
20			1340						
50	100				40	70		95	125

***Table 7.** O/W emulsion viscosities of Texaco Lone Rock wellhead crude (B5-14-47-27 W3M), using selected emulsifiers at three concentrations*

RPM	Viscosity (mPa·s) at 22°C								
	HO flow (ppm)			SRC-K1 (ppm)			Flothin F-2 (ppm)		
	500	1000	2000	500	1000	2000	500	1000	2000
0.5	3640	2390	2610	2730	340	340	4550	1360	680
1.0	3180	1930	2100	2270	170	170	3980	680	340
2.5									
5									
10	1550	820	680	1420	30	30	1700	190	85
20									
50									
100	30	30	50	50	15	15	35	25	30

especially, Flothin F-2 with its 18% final BS&W were quite incompatible.

Experiments with brines of reduced salinity showed, as expected, that for each emulsifier and emulsifier concentration, o/w emulsion stability increased with lower salt concentrations. While the effect was barely noticeable with the unstable HO Flow emulsions, it was quite evident with SRCK-1 and Flothin F-2, especially at lower concentrations.

Finally, the experiments with high-sand content wellhead crudes showed that o/w emulsion stability was adversely affected by the presence of sand. Only the most stable o/w emulsions (prepared with Flothin F-2 at 1000 ppm or higher) survived the presence of 15% v/v sand-in-oil, but sand dropout was rapid in the first 30 min (Table 8). The strongly destabilizing effect of sand at this sand concentration caused all other o/w emulsions to reverse to w/o emulsions on mixing. At lower sand concentrations (5 and 2% v/v sand-in-oil) other demulsifiers such as SRCK-1 and HO Flow could also be used and sand dropout slowed down (Tables 9 and 10).

Unrelated to the above laboratory study but in preparation for the field test described below, a group of three SRCK surfactants was evaluated by the Saskatchewan Research Council to determine their capacity to emulsify fireflood crude from the Norcen Energy Resources Bodo pilot. The wellhead crude was a w/o emulsion with a water content of 52% and a viscosity of 17,000 mPa·s. Emulsification procedures were the same as described above. Stability data on the resulting emulsions are presented in Table 11. The viscosities of the three emulsions varied within a narrow range (20–28 mPa·s), but only SRCK-1 generated an emulsion of acceptable stability.

Table 8. Sand dropout from O/W emulsions of Texaco Frog Lake wellhead crude (8-13-57-2 W4M) having a sand concentration of 15 vol% sand-on-oil (10 vol% sand overall)

Emulsifier (ppm)			Water (W) and sand (S) dropout (vol%) at room temperature			
			30 min	1 h	24 h	6 d
Blank (mixed with brine without emulsifier			w/o		w/o	
HO flow	1000		w/o		w/o	
SRCK-1	1500		w/o		w/o	
	1000		w/o		w/o	
Flothin F-2	1000	W+S:	20	24	34	
		S:	14	12	10	
	500		w/o			

Table 9. Sand dropout from O/W emulsions of Texaco Frog Lake wellhead crude (8-13-57-2 W4M) having a sand concentration of 5 vol% sand-in-oil (10 vol% sand overall)

Emulsifier (ppm)			Water (W) and sand (S) dropout (vol%) at room temperature			
			30 min	1 h	24 h	6 d
HO flow	1000	W+S:	w/o	w/o	30	32
		S:			6	0.8
SRCK-1	1000	W+S:	-	23	30	32
		S:	-	trace	1	1
Flothin F-2	1000	W+S:	-	12	16	26
		S:	-	-	1	1

Table 10. Sand dropout from O/W emulsions of Texaco Frog Lake wellhead crude (8-13-57-2 W4M) having a sand concentration of 2 vol% sand-in-oil (1.4 vol% sand overall)

Emulsifier (ppm)			Water (W) and sand (S) dropout (vol%) at room temperature			
			30 min	1 h	24 h	6 d
HO flow	1000	W+S:	–	28	28	29
		S:	–	0	trace	0.6
SRCK-1	1000	W+S:	–	8	24	27
		S:	-	0	trace	0.6
Flothin F-2	1000	W+S:	-	0	10	19
		S:	-	0	trace?	0.6

Surface Facilities and Injection Strategies

The following approaches to downhole emulsification have been tried or are being proposed for field application:

1. Chemical injection down the annulus
2. Chemical injection through hollow sucker rods
3. Chemical injection through a small tubing (spaghetti string).

Injection can be carried out batch-wise or continuously. Adding the chemical batch-wise through the annulus has probably been carried out most frequently, as it is a quick way of trying out the concept. The results have been inconsistent (no control over injection rate) and in some cases caused some further problems. Continuous injection through a hollow sucker rod or a spaghetti string is probably the best approach, but requires capital investments.

Continuous injection down the annulus would be a good compromise and requires minimal capital expenditures. However, in order to ensure that the emulsifiers quickly find their way to the pump, fluid levels in the annulus should be relatively low. High fluid levels do not preclude emulsification down the annulus, but it will take longer to saturate the fluids in the annulus with the emulsifier. This method of downhole emulsification has been tried at Murphy Oil's Eyehill and Lindberg fields.

For wells with a higher fluid level, the surfactant could be diluted with water in a 1:10 ratio. This will ensure a faster delivery of the emulsifying chemical down to the production pump where it is required for the emulsification process. The surface facility required to perform downhole emulsification is shown in Figure 1. For wells producing over 20% water only the facilities shown in the upper half of Figure 1 are required for the injection of chemical. For wells with a higher fluid level or a lower water cut (less

*Table 11. O/W emulsion stabilities of Norcen Bodo wellhead crude with SRCK emulsifiers at 20°C and 70°C**

Emulsifier	(ppm)	Water dropout (vol%) at 20°C 20 min	1 h	48 h
SRCK-1	1700	6	42	46
SRCK-3	1700	40	48	54
SRCK-4	1700	38	42	50
Emulsifier	**(ppm)**	**Water dropout (vol%) at 70°C 20 min**	**1 h**	**48 h**
SRCK-1	1700	50	50	50
SRCK-3	1700	58	58	59
SRCK-4	1700	52	52	60

than 20%) injection of water together with the emulsifying chemical is necessary in order to facilitate the emulsification process. Therefore, the entire injection system shown in Figure 1, comprising both chemical and water injection facilities, would be required.

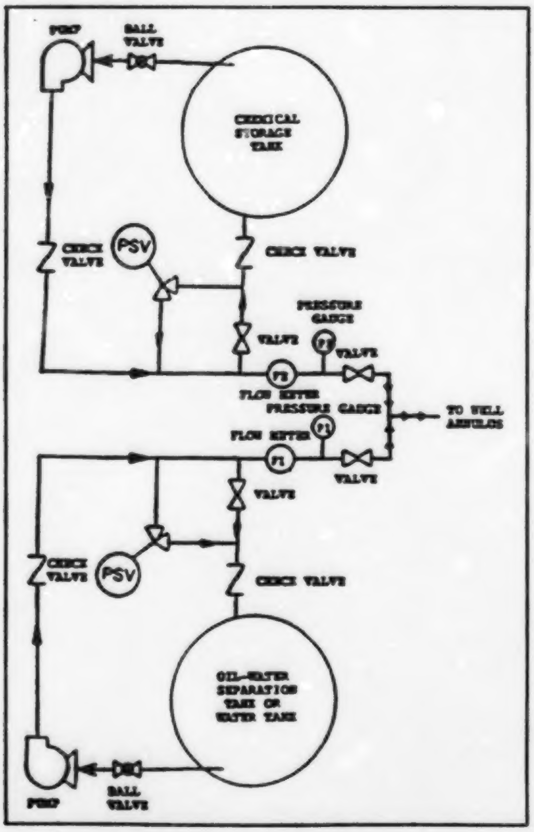

Figure 1. Chemical injection system.

FIELD TESTS

Background

Based on the results of the above laboratory investigations, a field test was to be performed by Texaco and CANMET/EMR at Frog Lake to demonstrate that increased production could be achieved from wells whose production was restricted by fluid viscosity and sand production. Organizational changes and rectification of these problems using conventional means led to the cancellation of the Frog Lake field test. However, another field test, conducted by Norcen Energy Resources at their Bodo fireflood on the basis of laboratory tests and recommendations from the Saskatchewan Research Council, successfully demonstrated the concept.[2]

Similar to many other fireflood projects, numerous production problems were observed in the maturing Bodo pilot, but most notable were the highly viscous w/o emulsions produced by many wells. The observed viscosities were as high as 50,000 mPa·s, representing a tenfold increase over primary viscosities. These increased viscosities impaired production significantly, led to high fluid levels and caused serious rod fall problems. In some cases the problem was so severe that rod hang-up was still observed at pumping speeds of less than one stroke per minute!

In a concentrated effort to address these problems and improve performance, Norcen tested numerous pumping systems, however, with limited success. The attempts also included the installation of diluent and produced water downhole injection systems using hollow sucker rods. No production improvements were achieved with the water injection system. The diluent system performed marginally and inconsistently, had its own problems (plugged hollow rods with waxy deposits) and, most important, suffered from unfavourable economics as the cost of the diluent was greater than the revenues from the incremental production. Thus, a more consistent and cost-effective process was needed to improve production.

As indicated by the above laboratory experiments and other o/w emulsification/surfactant screening studies undertaken by the Saskatchewan Research

Council, emulsification of the viscous production fluids downhole could result in a mixture more amenable to pumping. Out of three potentially-suitable surfactants, SRCK-1, SRCK-2 and SRCK-4 (see Table 11 and related text), SRCK-1 was selected for the Bodo field trial, principally because of its better short-term stability. With the hollow sucker rods and special downhole pumps already in place, implementation of the field test required only minor work.

Injection Facilities

The injection system at the Bodo pilot comprised water and chemical injection equipment. A schematic of the surface equipment is shown in Figure 2. The injection water used was produced water; it was stored in a tank at 50°C from where it was continuously fed to the wellhead by a small pump. The surfactant was stored in a drum and fed into the line downstream from the water injection pump by a small chemical pump. An in-line static mixer ensured effective mixing of surfactant and water. Constant water injection was important as the SRCK-1 surfactant tended to gel and plug the lines and/or hollow rods if not sufficiently diluted. A small shelter over the pumps, the chemical drum and the mixer prevented any freezing problems.

The downhole equipment involved a USS Oilwell diluent tubing pump, shown in Figure 3, which was specially designed to facilitate the mixing of injected

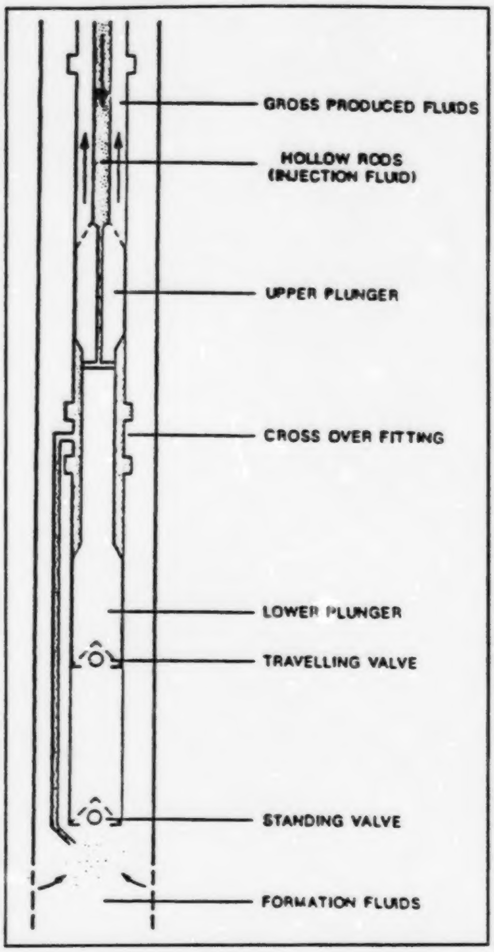
GROSS PRODUCED FLUIDS
HOLLOW RODS (INJECTION FLUID)
UPPER PLUNGER
CROSS OVER FITTING
LOWER PLUNGER
TRAVELLING VALVE
STANDING VALVE
FORMATION FLUIDS

Figure 3. Bottomhole assembly.

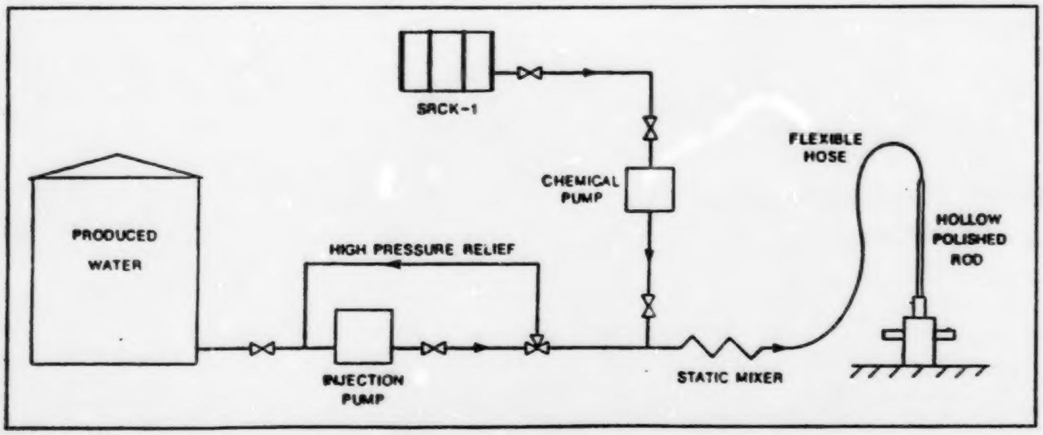
SRCK-1
CHEMICAL PUMP
FLEXIBLE HOSE
HOLLOW POLISHED ROD
PRODUCED WATER
HIGH PRESSURE RELIEF
INJECTION PUMP
STATIC MIXER

Figure 2. Surfactant injection system surface equipment.

fluids with formation fluids below its standing valve. This arrangement allowed for the formation of a low-viscosity o/w emulsion before the production fluids entered the standing valve, a design which resulted in better pump fillage and higher efficiencies. In other bottomhole pumps tested, the diluent was continuously injected inside the pump barrel. While rod fall was improved with this system, production rates were still low due to the inability of the high-viscosity fluids to flow into the barrel.

Field Test Results

Injection of the SRCK-1/produced water mixture was first tested in well L-10, which experienced emulsion viscosities in the order of 14,000 to 19,000 mPa·s and hence suffered from the production problems described earlier. Diluent injection using hollow rods and a USS Oilwell pump had been tried for a year. With this system the well produced 3 m^3 oil and 2 m^3 water per day, only up marginally from the pre-injection rates of 2.3 m^3 oil and 0.6 m^3 water per day. After the diluent injection was suspended because of wax plugging problems and poor economics, production returned to 1.9 m^3 oil and 1.2 m^3 water per day.

Downhole injection of the SRCK-1/produced water mixture at L-10 was started at a rate of 5 L surfactant and 4.5 m^3 water per day, representing the 0.1 wt% surfactant concentration which was determined as optimal. Oil production immediately increased by a factor of six to seven due to improved rod fall, which allowed a higher pump speed, and substantially improved pump efficiencies. A comparison of well performance before and after the implementation of downhole emulsification with SRCK-1 is shown in Table 12 and Figure 4. The improved pump efficiencies confirm that sufficient mixing of injected and produced fluids took place below the pump suction to allow the formation of o/w emulsions.

Following the promising performance achieved at L-10, identical systems were installed at wells J-8 and J-10 in the pilot area. As with L-10, these wells experienced high emulsion viscosities (25,000 mPa·s) and consequently production problems. Both water and diluent injection had been tried, but little improvement was observed. Again, once injection of the surfactant mixture was started, the wells responded immediately with improvements in rod fall velocity. With increased pump speeds now possible, oil production improved from less than fourfold (J-8) to sevenfold (J-10), as shown in Table 12 and Figure 4. Pumping efficiencies remained essentially unchanged at about 40–50%, however. This was due to the very low speeds at which both wells had been pumping before the surfactant injection systems were installed.

In an attempt to optimize the surfactant injection rate and concentration, a test program was conducted at L-10. While the results were not very conclusive because of changing well conditions and difficulties in measuring some properties accurately, it appears that oil production did not improve significantly with an injection rate greater than 3 L surfactant per day. This rate corresponded to an average SRCK-1

Table 12. Summary of SRCK-1 performance

	L-10			J-10			J-8		
Well	Before	After	Current*	Before	After	Current*	Before	After	Current*
Oil production, m^3/d	1.9	11.3	14.6	1.6	11.0	12.8	3.1	10.7	11.7
Water production, m^3/d	1.2	2.9	5.4	2.1	10.1	8.8	2.2	6.1	8.1
Gas production, m^3/d	0.6	0.7	0.7	0.3	1.1	1.4	0.6	1.0	0.6
Injection rate, m^3/d		4.6	3.6		4.1	3.5		4.0	3.8
Fluid level, m KB	29	241	222	261	318	376	261	290	376
Pump speed, spm	2.5	3.7	4.0	1.0	5.7	6.7	1.0	4.8	5.5
Stroke length, cm	188	188	188	245	245	245	245	245	245
Pump efficiency, %	18	73	85	41	49	41	59	48	47

* February 1987

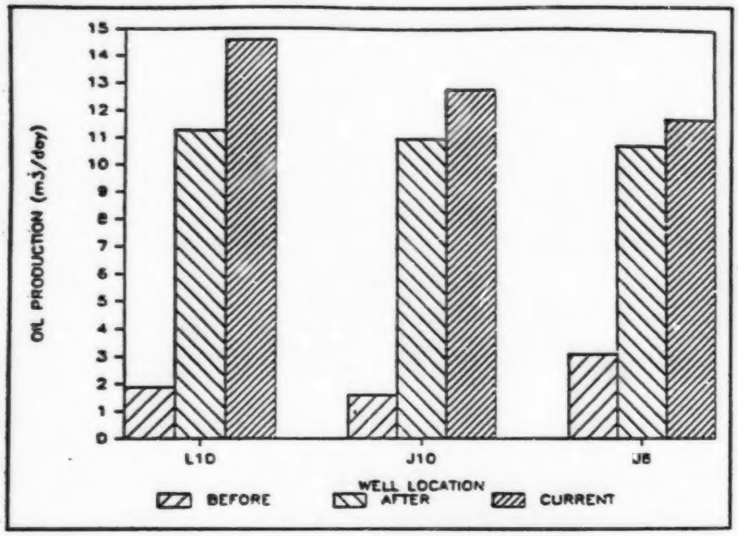

Figure 4. Production performance using SRCK-1.

concentration of 450 ppm based on total water (i.e., injected plus produced water) production. Because of the relatively high watercut of the formation fluids (52%), the volume of the injected fluids did not appear to be critical. The stability of o/w emulsion samples collected at the wellhead was very low, resulting in almost immediate dropout of the free water and making viscosity measurements difficult. However, the low viscosity of the wellhead fluids could be confirmed both visually and from the low tubing head pressures in the flow lines. Finally, as found earlier in the laboratory studies, the water content of the w/o emulsions, obtained after separation of the emulsified wellhead samples and removal of the free water, ranged from 12 to 24%, compared with 30 to 60% in the original emulsions before downhole emulsification with SRCK-1 was implemented. This confirmed the other capability of SRCK-1, i.e., that of a demulsifier.

Process Economics

Norcen concluded that based on the increased oil production, the economics of injecting a SRCK-1/water mixture downhole was very favourable. When operating the diluent injection systems, the additional expenses were approximately $1500 per month or almost $50 per day. With the incremental oil production amounting to no more than 1 m^3 per day, it follows that the production costs were more than $50 per incremental cubic metre. While an incremental oil production of less than 1 m^3 per day would just be sufficient to offset the operating expenses, this minimum production requirement could not always be attained.

In comparison, as shown in Table 13, the additional operating expenses for surfactant injection (trucking of water, propane, chemical costs) also amounted to $1500 per month, but these costs were easily paid out by the significant incremental oil production. Production costs were about $6 per incremental cubic metre. Capital costs of converting a well with a conventional rod pumping system to the downhole injection system described above averaged $25,000. With the sizable improvements in oil production, payout could be quickly realized.

CONCLUSIONS

1. Highly viscous wellhead crudes could be easily emulsified into low-viscosity o/w emulsions using a variety of emulsifiers.
2. Ease of emulsification, stability and viscosity of the o/w emulsions can be tailored to specific applications by selecting suitable emulsifier/

Table 13. Comparative economics of SRCK-1 surfactant and diluent injection systems (cost per well)

	Surfactant	Diluent
Capital costs		
Injection system	$25,000	$25,000
Operating costs		
Surfactant/diluent injection Costs per day	50	50
Production costs		
Surfactant/diluent injection Costs per incremental m^3	5-6	50–70

concentration combinations. The characteristics of the o/w emulsions generated ranged from less stable/more viscous with HO Flow to more stable/less viscous with Flothin-2.

3. In order to avoid additional treating problems, the compatibility of the selected emulsifier with the demulsifier in use in the field needs to be verified. The emulsification process should not result in a higher residual water content of the treated crude than that without emulsification.
4. High salinity of the water used for emulsification adversely affected the stability of the o/w emulsions. Sand also severely destabilized o/w emulsions. At high sand loadings, only emulsifiers found to produce the most stable emulsions without sand were capable of generating relatively stable o/w emulsions. Sand dropout was rapid, however. At lower sand loadings there was a wider choice of emulsifiers and sand dropout slowed down.
5. In field tests SRCK-1 was found to be an effective emulsifier for the downhole generation of o/w emulsions of Bodo fireflood crude. This surfactant was more than compatible with the field demulsifier and indeed acted as a demulsifier itself.
6. Injecting the emulsifier solution outside the pump suction provided for effective mixing with the formation fluids. The formation of o/w emulsions greatly reduced viscosity, which in turn improved pump fillage, rod fall and in some cases, pump efficiencies. The overall result was a significant production improvement, ranging from fourfold to sevenfold.

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